[COMMITTEE PRINT]

COAL COMBUSTION

REPORT

PREPARED BY THE

SUBCOMMITTEE ON ENERGY RESEARCH, DEVELOPMENT AND DEMONSTRATION
(Fossil Fuels)

OF THE

COMMITTEE ON
SCIENCE AND TECHNOLOGY
U.S. HOUSE OF REPRESENTATIVES
NINETY-FOURTH CONGRESS
SECOND SESSION

Serial YY

OCTOBER 1976

Printed for the use of the Committee on Science and Technology

U.S. GOVERNMENT PRINTING OFFICE
74-260 WASHINGTON : 1976

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402
Stock No. 052-070-04092-1

COMMITTEE ON SCIENCE AND TECHNOLOGY

OLIN E. TEAGUE, Texas, *Chairman*

KEN HECHLER, West Virginia
THOMAS N. DOWNING, Virginia
DON FUQUA, Florida
JAMES W. SYMINGTON, Missouri
WALTERS FLOWERS, Alabama
ROBERT A. ROE, New Jersey
MIKE McCORMACK, Washington
GEORGE E. BROWN, Jr., California
DALE MILFORD, Texas
RAY THORNTON, Arkansas
JAMES H. SCHEUER, New York
RICHARD L. OTTINGER, New York
HENRY A. WAXMAN, California
PHILIP H. HAYES, Indiana
TOM HARKIN, Iowa
JIM LLOYD, California
JEROME A. AMBRO, New York
CHRISTOPHER J. DODD, Connecticut
MICHAEL T. BLOUIN, Iowa
TIM L. HALL, Illinois
ROBERT (BOB) KRUEGER, Texas
MARILYN LLOYD, Tennessee
JAMES J. BLANCHARD, Michigan
TIMOTHY E. WIRTH, Colorado

CHARLES A. MOSHER, Ohio
ALPHONZO BELL, California
JOHN JARMAN, Oklahoma
JOHN W. WYDLER, New York
LARRY WINN, Jr., Kansas
LOUIS FREY, Jr., Florida
BARRY M. GOLDWATER, Jr., California
MARVIN L. ESCH, Michigan
JOHN B. CONLAN, Arizona
GARY A. MYERS, Pennsylvania
DAVID F. EMERY, Maine
LARRY PRESSLER, South Dakota

JOHN L. SWIGERT, Jr., *Executive Director*
HAROLD A. GOULD, *Deputy Director*
PHILIP B. YEAGER, *Counsel*
FRANK R. HAMMILL, Jr., *Counsel*
JAMES E. WILSON, *Technical Consultant*
J. THOMAS RATCHFORD, *Science Consultant*
JOHN D. HOLMFELD, *Science Consultant*
RALPH N. READ, *Technical Consultant*
ROBERT C. KETCHAM, *Counsel*
REGINA A. DAVIS, *Clerk*
MICHAEL A. SUPERATA, *Minority Counsel*

SUBCOMMITTEE ON ENERGY RESEARCH, DEVELOPMENT AND DEMONSTRATION (FOSSIL FUELS)

KEN HECHLER, West Virginia, *Chairman*

THOMAS N. DOWNING, Virginia
WALTER FLOWERS, Alabama
MIKE McCORMACK, Washington
RAY THORNTON, Arkansas
HENRY A. WAXMAN, California
PHILIP H. HAYES, Indiana
MICHAEL T. BLOUIN, Iowa
ROBERT (BOB) KRUEGER, Texas
MARILYN LLOYD, Tennessee
TIMOTHY E. WIRTH, Colorado

ALPHONZO BELL, California
GARY A. MYERS, Pennsylvania
DAVID F. EMERY, Maine
LARRY PRESSLER, South Dakota

SUBCOMMITTEE STAFF

ROBERT C. KETCHAM, *Counsel*
LEE WALLACE, *Minority Counsel*

LETTER OF TRANSMITTAL

House of Representatives,
Committee on Science and Technology,
Washington, D.C., October 1976.

Hon. Olin E. Teague,
Chairman, Committee on Science and Technology, House of Representatives, Washington, D.C.

Dear Mr. Chairman: During the oversight hearings on coal combustion research and development, the Subcommittee clearly identified that a very large gap in technology exists if this nation intends to revive coal as a major source of our future energy requirements.

The combustion of coal and its use in an environmentally acceptable manner for the raising of steam to produce electricity and to generate heat was the basic subject of concern to the Subcommittee. The Subcommittee has identified the areas of concern which the hearings pointed out in the findings and conclusions accompanying this report, and urges the full Committee on Science and Technology as well as all interested parties to share this concern.

Sincerely,

Ken Hechler, *Chairman,*
Subcommittee on Energy Research,
Development and Demonstration (Fossil Fuels).

CONTENTS

INTRODUCTION

This Nation presently possesses one fifth of the world's remaining coal resources—some 4 trillion tons. The coal already used in the United States fueled its initial growth as an industrial and world power. Coal fired steel mills forged the tracks that coal driven locomotives travelled in opening up the Western frontier. By the turn of the century, coal supplied 90 percent of the country's energy consumption. In absolute terms, U.S. coal production has increased since the turn of the century, though there have been large fluctuations in total tonnage in the last 30 years (see figure 1). However, as domestic oil and natural gas became available at a competitive price, coal consumption grew less rapidly. By 1950, coal provided 38 percent of the Nation's energy consumption and by 1972, only 17 percent.[1]

This decreased dependence on coal has also been strongly affected by the passage and enforcement of environmental legislation. The existing methods of mining and using coal made it unattractive from an environmental viewpoint. By 1970, the future of coal as a primary fuel was in question.

This uncertainty in the future role for coal was resolved in part by the Arab oil embargo in 1973, the subsequent price increase of oil and then the worsening natural gas shortages. These events highlighted once again the value of our coal resources and turned thoughts to strategies for increasing its production and use. Another factor in reviving coal is the recognition of the interconnection of our economy with energy consumption. As a consequence of these two factors, the Federal Energy Administration projects coal production in 1985 to be about one billion tons.* This represents an almost fifty percent increase over 1975 production of 635 million tons.

This increased coal production will be used in many ways, using both existing and soon to be developed technologies.

---

[1] U.S. Federal Energy Administration. National Energy Outlook (Washington, 1976) pp. 163–165.

* This estimate was provided to the Committee in its hearing in July of 1975. The President has recently announced a similar goal as part of his National Energy Plan.

Coal Consumption By Sector, 1935–72

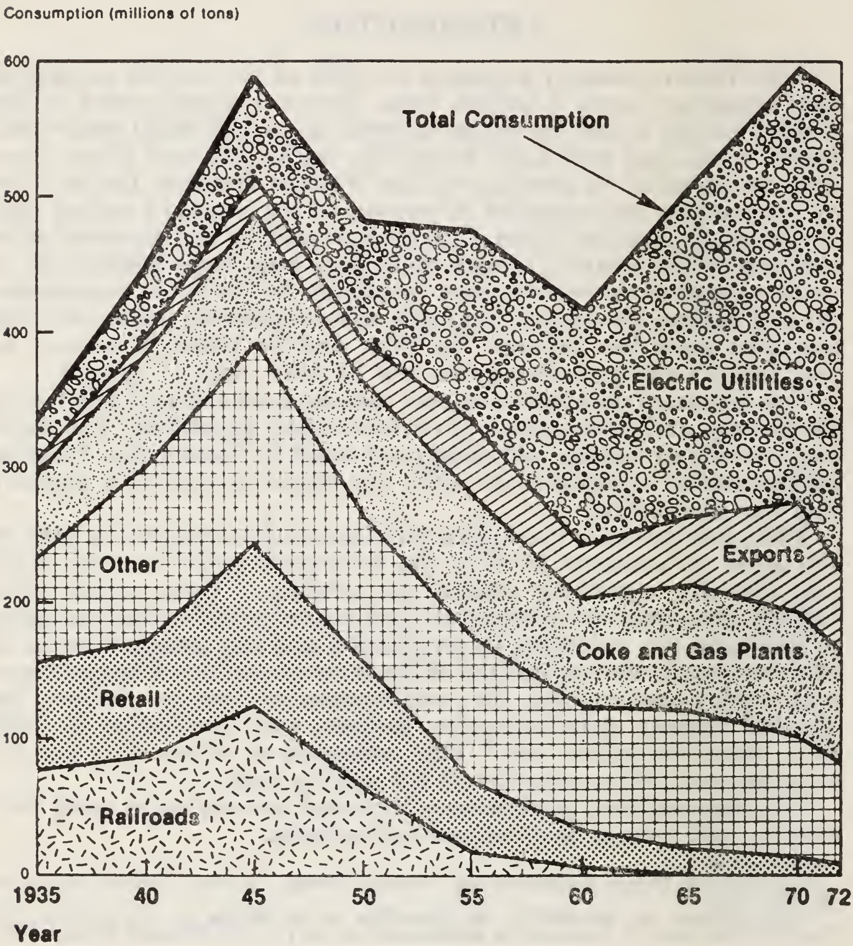


FIGURE 1

TABLE 1.—*Methods for coal to energy*

Method	*Commercial*
I. Direct Firing: requires clean coal or clean-up methods for compliance:	
1. Lump (grate) firing:	
(i) Hand fired	Yes.
(ii) Stoker fired	Yes.
2. Crushed firing—fluid bed:	
(i) Ballasted	No.
(ii) Unballasted (Ignifluid)	Yes.
(iii) Fast fluidized bed (Szikla-Rozinek)	No.
3. Pulverized (fine ground) firing:	
(i) Standard pulverized coal combustion (<100 microns)	Yes.
(ii) Ultra-fine ground (<10 microns)	No.
II. LOgas: Producer-gas/water (syn) gas (CO, H_2, N_2 (CH_4)) (100 to 300 Btu sec. cubic foot):	
1. Fixed bed, vertical shaft (Wellman, Lurgi)—counter flow	Yes.
2. Fluid or fast fluid bed	No.
3. Entrained (fine grind: Koppers Totzek)	Yes.
NOTE.—The last 3 are commercial on a proportionately small scale.	
III. Pyrolysis: Coking ovens—yields are:	
(1) Tars (can be used for some chemical feedstock)	
(2) Coal gas (500 Btu per cubic foot of H_2, CO, CH_4)	
(3) Coke (feed for gas producers)	
NOTE.—Emissions are under control using continuous vertical retorts.	
IV. HIgas: SNG from coal (1,000 Btu per cubic foot):	
1. HYGAS process	No.
2. CO_2 acceptor process	No.
3. Bi-gas process	No.
4. Self-agglomerating burner	No.
5. Synthane process	No.
6. Steam-iron process	No.
V. Liquefaction: SNO from coal:	
1. Solvation (solvent refining)	No.
2. Direct catalytic (Synthoil: $CH_{0.9}$ to $CH_{1.1}$)	No.
3. Methanol: from syngas ($CO+2H_2$ to CH_3OH)	Yes.
4. Fischer-Tropsch	Yes.
5. Bergius	Yes.
NOTES.—(1) Units in principal can be atmospheric or pressurized. (2) Most units are continuous; small water gas may be intermittent. (3) Sulfur is removed as H_2S by standard methods for the cold gas; hot gas cleaning is a problem. (4) Gas can be delivered and used hot, with ash and S, or cold cleaned. (5) Efficiencies are 85 to 90 percent used hot; 70 to 75 percent used cold and clean.	
VI. Combination Fuels:	
1. Coal dispersion in oil	No.
2. Coal dispersion in methyl fuel	No.
VII. Direct Power:	
1. Diesel (ultra fine grind)	No.
2. MHD	No.
3. Gas turbine:	Yes.
(i) Low-Btu gas	Yes.
(ii) Direct fired clean coal	No.
VIII. Mixed Methods:	
1. Two stream cleaning options by deep cleaning: clean stream (50 to 80 percent of total) to conventional equipment with no FGD necessary; dirty stream to specially equipped boilers or gasifiers	No.
2. Partial pre-cleaning (low efficiency) with partial (low efficiency) cleaning of inter stage gas with (low efficiency) FGD. Overall high control efficiency	No.

NOTE.—Emissions are under control using continuous vertical retorts.
Source: Testimony of Dr. Robert Essenhigh before the Energy Research, Development, and Demonstration (Fossil Fuels) Subcommittee, July 31, 1975.

These technologies can be characterized under three headings: (1) direct combustion of coal or coal mixed with another fuel, (2) conversion of coal to liquid or gaseous fuels, and (3) combined cycles utilizing gas turbines or MHD generators in tandem with traditional steam turbines.

The direct combustion technologies were discussed before the subcommittee on July 29, 30, and 31, 1975. The hearings focused on the research and development required before these technologies could be used commercially. However, they also uncovered how these R. & D. programs must be tailored for the different needs of different users. The utility industries need large scale (100 to 1,000 Mw) installations with high reliability and straightforward maintenance. The other industrial users need smaller units (10–100/Mw) for raising steam or process heat to be used for such products as steel, glass, refractories and cement. This smaller unit market is particularly important. Because of the direct correlation between industry and jobs, energy shortages have a dramatic effect in this sector. It suffers more quickly in an energy shortage and the costs associated with environmental clean up are higher relative to the larger utility users. The hearings underlined the fact that a successful program will address such other issues which surround increased coal production.

Issues Surrounding Increased Coal Production and Use

The concerns discussed in this section have an impact on direct combustion technologies in various ways. For example, there are technical concerns which are specific to each method but technical improvements in the mining of coal will impact all coal tehnologies equally.

TECHNICAL CONCERNS

The immediate problems facing direct combustion of coal are two: more efficient combustion and emission controls. The need for more efficient combustion arises from the fact that even our vast coal resources are finite. In fact, of the 4 trillion tons of coal mentioned earlier, approximately 400 billion are recoverable with present technologies. Aside from the clear need for new coal recovery methods for the remaining 3.6 trillion tons (which was the subject of a subsequent set of hearings by the subcommittee, July 27, August 3, 4, 5, September 10, and 16, 1976), it is important to use coal as efficiently as possible. This is one of the motivations behind the development of fluidized bed combustion of coal.

The problems of emission control are governed by the Nation's continued commitment to a clean environment. Control of sulfur, in particular sulfur dioxide (SO_2) emissions, has been of paramount importance. Though sulfates and nitrogen oxide emissions are becoming prominent, technical attacks have been mounted most aggressively on SO_2 removal. Table 2 lists some of the prominent desulfurization approaches.

TABLE 2.—*Sulfur control strategies*

I. Low sulfur coal
II. Pre-Combustion Cleaning:
- (1) Mechanical (physical) (inorganic sulfur only):
  - (i) dry methods.
  - (ii) wet methods (floatation etc.: Trent process etc.).
- (2) Chemical (total sulfur)
  - (i) hydrodesulfurization.
  - (ii) oxydesulfurization.
  - (iii) solvation or other removal of mineral matter.

III. Inter-Cleaning:
- (1) Gasification strategy: sulfur removed as H_2S in an inter stage of the processing:
  - (i) Producer/water (synthesis) gas—including combined cycle operation.
  - (ii) Pyrolysis (destructive distillation in coke ovens).
  - (iii) Indirect methane production (HI gas).
- (2) Liquefaction strategy:
  - (i) Solvation (SRC).
  - (ii) Synthoil production.
  - (i) Atmospheric.
  - (ii) Pressurized.

IV. Post-Cleaning
- (1) Stack gas cleaning (FGD).
- (2) Tall stack dispersion (dilution[1]).

SOCIOECONOMIC AND ENVIRONMENTAL CONCERNS

Many of the environmental problems facing direct combusion are common to any energy technology that utilizes coal. Among these are health and safety in mining technologies, reclamation of strip-mined land, and appropriate use of the scarce water resources in the West.

A concern common to the development of Western coal, and to some extent Eastern coal, is the impact on the small and relatively poor communities or Indian reservations where the coal mines and possibly electric power plants are likely to be built. During construction, a boom town situation will occur. The local service institutions including schools and hospitals may not be able to handle the burden without new facilities. Therefore, public and private efforts must go hand in hand with the resource development to avoid the adverse effects of this kind of development.

FINANCIAL AND ECONOMIC CONCERNS

Though one can devise labels that separate environmental, regulatory and financial concerns, the reality of coal development intertwines all these areas. Environmental regulations have added real costs and inflationary costs due to time delays incurred by meeting all the requirements of regulating agencies. These have pushed the capital costs associated with a traditional coal burning electrical generation plant above those for a nuclear electric plant. In the case of the electric

[1] Dispersion is not advocated as a strategy for control of sulfur emissions but it is advanced as an interim strategy for control of ambient air levels.

utilities, the added costs, rapid inflation and an unadjusted rate structure have made front end capital difficult to obtain. This is especially so for new technologies like fluidized bed combustion. Industral users have their problems in converting too, chief of which is the added costs of handling and using coal. These delay the decision to switch to coal and thus affect the commercial viability of improved combustion technologies.

The financial community is also concerned that a large amount of capital must be formed and devoted to the energy market as a whole if the country's energy goals are to be met. It is generally agreed that the economy can generate enough capital but it is not clear how the financial resources should be allocated to new technologies.

REGULATORY CONCERNS

The utilities and smaller industrial users of coal must meet many sets of regulations including environmental regulations. These regulations affect land, air and water use and all of these requirements add to the time and costs associated with the plants. In addition the worst fears of the participating firms is that once the requirements are met, someone will change them. Industry could better address itself to solutions for environmental matters with a stable regulatory climate in the environmental area.

The rate structures of electrical utilities are determined by Federal and State agencies. The rate of return has been fixed for many years in most States and has not been adjusted for the increased rates of inflation in the recent past. To further complicate matters new plants cannot be written into the rate base of most utilities during construction.

OVERALL ENERGY POLICY

Energy policy as it evolves will be a joint effort by both the President and the Congress. The choices that must be made will have to balance the contributions from programs to restrict consumption or change consumption patterns and programs which will increase energy supply. Near term needs must be balanced against long term needs. The technologies using coal and uranium must be placed in the perspective of energy from the sun and possibly fusion. The size of the coal resource, its familiarity and the severity of the near- and mid-term needs for energy assure that coal will be used. The form of its use and the timing of new technologies allow room for governmental action. The problems are ones of accelerating not simply developing devices and methods but the meshing of Government programs with already functioning structures in private industry.

The significant role of coal and the need for research and development in coal technologies was acknowledged by Congress when it established the Office of Coal Research in 1961. More recently, passage of the Energy Supply and Environmental Coordination Act (Public Law 93–319, 88 Stat. 246) provides authority in section 2 for the Federal Energy Administration to order oil and natural gas burning electric generators to convert to the use of coal. This program was continued and intensified with the passage last year of the Energy Conservation and Production Act, Public Law 94–385. As a consequence, it is now

part of our national energy policy that more coal must be used. It now remains to develop more efficient, cleaner and economically successful techniques for insuring that coal is burned by the widest community of possible users.

Organization of This Paper

This paper will examine research and development efforts in different coal combustion technologies. These efforts are set in a general perspective of how coal has been used and produced. In addition, a short history of coal research sets forth the background for the current problems. Then the status of specific technologies is examined. Fluidized bed combustion, viewed by many as the most exciting and novel coal combustion method is described. The other existing and less developed technologies are discussed as possible alternatives to fluidized bed combustion. Finally the energy conversion alternatives study (ECAS), which is to evaluate some of these combustion alternatives, is discussed in the appendix.

FINDINGS AND CONCLUSIONS

While the United States has recently adopted a policy to increase the use of coal as a boiler fuel for electric generating units, the subcommittee hearing record reveals the lack of any coherent, National policy on coal research and development even in the recent past. The Subcommittee found on the basis of the testimony it received that there had been no significant breakthrough in coal combustion technology since the late 1920's. While there apparently had been a gradual improvement in coal combustion technology and power generation efficiency, there had been nothing in the way of a new technology or dramatic change in this field. The only technology on the horizon is that for atmospheric fluidized bed boilers which will not be commercially operative until the 1980–85 time frame.

Furthermore, our hearings showed a desire, on the part of ERDA, to rely exclusively on one area of technology to improve the use of coal for combustion; i.e., the fluidized bed. Subsequent to our hearings, ERDA has expanded the number of technologies for their coal combustion research by adding a coal and oil slurry program. However, this was modestly funded; and the Subcommittee later learned it was not given a high priority. For example, when funds had to be reprogrammed for construction of an MHD facility, a long-term technology, the coal and oil slurry program was one of the first to go.

At Subcommittee insistence, this program of near-term technology was restored to almost its full level so that no cuts were made.

The Subcommittee feels that substantial benefits could be realized from increased research into the boiler use of coal and oil mixtures. ERDA should reconcile any technological problems remaining with this near-term option and should devise an accelerated program to rapidly transfer it to industry. Many non-technological constraints may inhibit the potential near-term impact of this technology.

Substantial additional National benefits can accrue from successful research in the retrofitting of industrial oil and gas boilers to the use of coal. Our National policy to increase the use of domestic coal will be furthered, but more importantly, jobs vulnerable to gas or oil curtailment will be protected.

In regard to this, it should be noted that ERDA is conducting research work on industrial-size atmospheric fluidized bed boilers for new plants. However, more work needs to be done on the potential for retrofitting industrial plant boilers with fluidized bed equipment. Such retrofitting would accelerate the utilization of coal in our Nation's economy. However, most of the testimony received showed a reluctance on the part of ERDA, the utilities, and industry to investigate the retrofitting option. In many cases this was based on a lack of information or misinformation as to outage times and economics. The Subcommittee hopes that ERDA's program in retrofitting industrial boil-

ers will include cooperation and coordination with industry to maximize the retrofitting option.

Low sulfur coal reserves in the West and the East are not being fully utilized. Testimony revealed that the increased production of low sulfur coal had not been seriously considered by the utility industry as an alternative to technologically intensive solutions. EPRI testified that they considered the option of installing new facilities for low sulfur coal to be equally desirable to high technology solutions such as coal gasification, where costs were equivalent. However, to date, the level of production necessary to justify their reliance on low sulfur coal has not come forth, requiring them to pursue these technologically intensive solutions.

Members of the subcommittee felt that the low sulfur coal reserve base represented a very real alternative to further capital expenditure by utilities for new technology. However, recognizing the large capital expense required to open new mines, members of the subcommittee wished to see further refinement of data. They wanted to know the amount of coal which can be obtained from either existing deep mines that are currently in operation or from those deep mines that have been shut down in the Eastern United States. Discussion between the panel and the witnesses revealed that the Bureau of Mines does not seek this data, on the basis that this is proprietary information of the coal companies. Members felt, however, that this presented a real option for the country's energy demand, and that ERDA should consider this question jointly with the Bureau of Mines and others; ERDA agreed to research this matter.

Further testimony from EPA indicated that the low sulfur coals of the West may pose further environmental problems. EPA stated, "Under the present environmental control standards set by the Environmental Protection Agency, many of the low sulfur coals will meet the standards, both sulfur dioxide and particulates, at the present time. It depends, though, critically on the nature of the coal. The very good Eastern coals, such as Mr. Hechler referred to, will meet both the particulate and the sulfur dioxide standards without difficulty. However, as you move into the West, some of the coals are really quite different. They have lower Btu content; they have higher ash content; and there are problems in that some of the coals which might have a .7 percent sulfur by weight would not meet the sulfur dioxide emission standards because of the different problems which are created by the lower heat content, the high ash content."

Such testimony indicates that the Eastern coal should be vigorously developed.

With regard to specific areas of research, the subcommittee found that the research and development program fluidized bed technology being conducted by ERDA, has only recently been accorded to high priority which it deserves. The 30 MWe fluidized bed boiler project, being constructed by ERDA at Rivesville, W. Va., was begun in October 1972, and is actually an extension of a program which began in 1965.

Witnesses testified that there had been an 18-month delay in the projected construction time due to longer order times than normal, in this inflationary period, and because of changes in West Virginia's environmental standards. While such delays are not unusual, some precautionary planning can be made. The Subcommittee, however, notes with approval the fact that ERDA is requesting authorization for a 200 MWe fluidized bed combustion demonstration plant this year. This plant would represent one module of a commercial-size power plant.

Another area of coal combustion research that must be pursued is the structure and characterization of coal. An examination of the literature will show that much research has been done on particular seams of coal. However, any attempt to generalize from one type of coal to the other has met with unrewarding results.

More research work also needs to be done on the ability of coals to be cleaned. While the Bureau of Mines has been conducting extensive work on the washability of coals, attempts to measure the efficiency of coal-cleaning methods has been disappointing. This is due to the numerous variables inherent in the task. The variables include the characteristics of the coal to be cleaned, the particular method of operation, the amount and nature of impurities to be removed, the percentage of near-gravity material, and the size range.

This area of research could benefit from Government activity or funding, and would be corollary research to the efforts to categorize the structure and composition of coals.

74-260—77——3

SECTION 1—COAL AND COMBUSTION RESEARCH

Coal Characteristics

Coal is a combustible natural solid formed from fossilized plants. It is generally found as a layer in sedimentary rock, which differs greatly in thickness, depth below the surface, and areal extent. It is dark brown to black in color and consists primarily of carbon (more than 50 percent by weight) in the form of numerous complex organic compounds. The composition of coal varies considerably from region to region and even within given fields. Coals are classified on the basis of three specific characteristics: (1) carbon content; (2) heating value; and (3) impurities. The first two characteristics are used in ranking the coal. Anthracite and bituminous coals are primarily ranked on the basis of fixed carbon content. Subbituminous coals and lignite, which contain less fixed carbon, are ranked on the basis of heating value. Approximately 70 percent of all U.S. coal is bituminous or subbituminous, while only about 1 percent is anthracite.

In addition to being ranked, coals are graded on the basis of the impurities that they contain. Certain impurities (including moisture, ash and sulfur) present problems when coal is processed and utilized. Moisture content is related to rank; the higher the rank the lower the moisture content. Moisture ranges from 1 percent in some anthracite to more than 40 percent in some lignites. The ash content of coal varies considerably, even within a single seam, making proportional generalizations difficult. Ash is the amount of non-combustible inorganic materials that the coal contains, and affects the heating value of that coal. Ash varies greatly, from 2.5 to 32.6 percent.

The sulfur content of U.S. coal ranges from 0.2 to 7.0 percent, varying considerably between geographic regions. Low sulfur coal (coal having a sulfur content of 1 percent or less) occurs both in the Eastern and Western United States. The U.S. Bureau of Mines estimates that there is approximately 167 billion tons of coal west of the Mississippi River and 32 billion tons east of the Mississippi River, which is minable. However, the western coals have a lower heating value than do the eastern coals.

The characterization of coal is one area of research that has received little attention in the past. As can be seen from the foregoing discussion, coal is characterized on the basis of its external properties, rather than its inherent structure and constitution. Members of the coal industry have seen very little in the way of short-term rewards from such research, despite the fact that a breakthrough could have a significant potential payoff. One of the witnesses who appeared before our Subcommittee, Professor Robert T. Essenhigh, urged further funding in this area. He said, "The chief problem is that the subject needs a good new idea that would synthesize all the diverse factual data we have at present—in fact, it needs an equivalent to Niles Bohr to

invent the equivalent to the Bohr atom. This is something that no one can write proposals on. However, even Bohr needs sufficient data to work from to stimulate the imagination." Further research work to gather such information is appropriate. This seems to be an appropriate area where the Government, rather than industry, will have to take the lead in funding.

History of Combustion Research [1]

Research on coal combustion and related matters has been conducted for well over a century. In fact, references to studies on coal can be found extending back for more than three centuries, but the first known paper on coal combustion was published in 1845. This report appeared in the Philosophical magazine, and was concerned with an explosion which had recently occurred. For the next 60 or 70 years the literature in coal research was mainly concerned with reports on explosions and methods for increasing safety of this combustion. Utilization of coal was given very low priority, and only minor advances were made in this area.

Gradually research on explosions involving coal gave way to direct research on the utilization of coal, but the research shifted in the nineteen twenties when engineers began to turn their attention to the more lucrative area of petroleum research. From then on, most research conducted on coal was of a somewhat unsophisticated nature.

The volume of literature published was large between World War I and World War II, but the quality of research was not commensurate with research in other energy areas. In 1924, Harvey compiled 5,000 titles of papers on pulverized coal firing alone, and by 1930, in a list by Knabner, the list had grown to over 10,000.[2] The list of papers on the subject of the combustion of coal was even more monumental. However, the quality did not keep pace with the quantity of literature. This is not to say, though, that some important work was not done. Papers by Nusselt on diffusion analysis, published in 1924 and a paper by Tu, Davis, and Hottel on carbon sphere combustion [3] were brought to the attention of the subcommittee.

Unfortunately, since World War II the pattern of research has continued to be irregular. The enormous volume of literature that has accumulated can be seen to be a complicating and inhibiting factor to any further systematic research for coal combustion and utilization. An examination of the literature will show that much research has been done on particular seams of coal. Any attempt to generalize from one type of coal to the other has met with unrewarding results. It is evident, that further work must be done on the structure and characterization of coal, in order to systematize further experimentation and work in this field.

The efforts of scientists and engineers have been devoted to four areas of research. They have mainly investigated pulverizing of coal, combustion of coal, cleaning of coal, and coal-oil mixtures and blending.

---

[1] A large portion of this section was taken from a paper delivered by Prof. Robert Essenhigh, NSF/OCR–RANN Meeting, October 1974.
[2] Ibid.
[3] Ibid.

Investigation into pulverized coal began in the 1920's. This renewed interest came about because engineers were trying to increase the steam rates in their boilers, but could not reach desired levels with the grate-combustion techniques then in use. This switch in technologies resulted in a wholly new approach to burning coal. Engineers now dealt with fine coal dust instead of large, gritty mixtures. This smaller sized coal lent itself to more technological innovation than did the earlier technology.

In 1922, Winkler filed an historic patent in Germany.[4] His idea was to increase the rate of gas flow upward through a granular bed of coal to buoy up each particle in the bed. When the upward thrust on the particle was equaled by the downward drag of gravity, the particles flowed freely, and the bed took on the character of a boiling liquid. A decade later, American engineers coined the term "fluidization" to denote Winkler's procedure. Winkler commercialized this process in 1926, but very little further development was done on his technology.

An interesting ancedote suggests what coal combustion research may have missed with this process. In the mid-1930's, M. W. Kellogg Company and Esso were at work on a technique for cracking distillate oils by passing oil vapor together with a fine clay catalyst through a heated coil. Results obtained in a small coil were good, but the larger coal performed badly. A group of Kellogg and Esso engineers were returning from Germany, where they had just visited the Winkler gasifier.

One of the engineers suggested utilizing this fluid bed technique to crack the distillate oil. This idea was pursued and within a few weeks a pilot unit was in operation. The large catalytic cracking units in use in the petroleum industry today are the result of that visit to the Winkler process in Germany.

In the 1950's, Albert Godel developed his Ignifluid boiler. This consisted simply of a fluidized bed of coal upon a traveling grate. Godell made the remarkable discovery that the ash of almost all coals is self-adhering at a temperature in the vicinity of 1100° C, no matter how much higher the ash-softening temperature may be. Godell burned the pulverized coal at this temperature, causing the ash to agglomerate into larger and larger particles until the ash eventually fell out of the fluidized bed under its own weight. This technology was originally used for smaller boilers, but has recently been promoted for use in larger units, by Babcock-Atlantique.

Also in the 1950's, Pope, Evans and Robbins began development and promotion of their fluidized bed concept. This development was eventually adopted as a project by the Office of Coal Research. The history of this project will be discussed in further detail in the next section.

While research on pulverized coal has been in the area of combustion, most of the literature on pulverization of coal has been concerned with the correlation between the energy input to the process and the size reduction. Carey and Holton have calculated that of 30 Kw/hr needed to grind a ton of coal in the mill, 8 Kw/hr were lost to

[4] F. Winkler, U.S. Patent 1,687,118 (October 9, 1928).

the atmosphere, 9 Kw/hr went into heating the air purged, 7 Kw/hr were used to evaporate moisture, and 6 Kw/hr heated the coal.[5]

Most of the literature also reveals that the energy input varies with fineness of grinding, ranging from 3 to 4 Kw/hr/ton for coarse crushing through 20-30 Kw/hr/ton for fine grinding to 100–1000 Kw/hr/ton for super-fine grinding.

Two important theories have been developed in pulverization research to explain the fundamental relationship between energy input and size reduction. The first theory is known as Kick's Law, according to which the energy needed to effect equal reduction of pieces does not vary with the size of the starting piece, and is applicable to homogeneous, elastic bodies.[6] The second important pulverization theory is known as Rittinger's Law, according to which the energy is proportional to the increase in surface area, consequent upon the size reduction. In the latter, energy lost in plastic deformation and thermal vibrations is neglected, and in both cases the kinetic energy of fragments is neglected.[7]

Mr. Hahns Rohrbach has provided the only published technical statement on ILOK technology which was developed as being a way of pulverizing the coal and simultaneously removing all sulfur. This was in the Journal Motortechnishe Zeitschrifte on pages 379–385, (1971). The title was "On Some Problems of the Coal Dust Motor". This technology has aroused the interest of researchers, and is being investigated by numerous parties.

There have been numerous studies on the cleaning of coal, beginning with a publication by Stutz in 1880.[8] However, the first systematic study of cleaning of coal to develop correlations was done in 1924.[9]

Another area of coal cleaning, coal washability, was begun in 1929, when the Bureau of Mines began a study of the washability (the ability of coal to be cleaned) of western coals. Since 1950, the Bureau of Mines has been conducting an extensive study on the eastern coals, specifically, from the States of Kentucky, Pennsylvania, Tennessee, Virginia and West Virginia to determine the washability characteristics of these coals.

While many fine studies have been done of the ability of coal to be cleaned, the attempts to measure the efficiency of the cleaning process have been disappointing. The main reason for this is that there is no standard method of measuring the efficiency which has developed. Numerous commentators have attempted this task, but after forty years of articles, no standard has been developed.[10]

---

[5] Carey, W. F., and Holton, E. M., Trans. Inst. Chem. Engrs. (London) 24, 102–8 (1946).
[6] Kick, F. Dingleris Polytech. J., 247, 1–5 (1883).
[7] Rittinger, P. Von, Lehrbuch der Aufberitungskunde, Ernst Und Korn, Berlin, 1867, 595 EP.
[8] Stutz. S., AIME, 9, 461–77 (1880).
[9] McMillan, E. R., and Bird, B. M., University of Washington Engineering Experiment Station, Bulletin, 28 (1924).
[10] Handcock, D., *Alabama Geol. Survey, Monograph* No. 7, (1912), pp. 234–45. Delamater, G. R., *Coal Age.* 5, 723-9 (1914). Drakeley, T. J., *Trans. Inst. Mining Engrs. (London)*, 54, 418–59 (1917–18) ; 59, 86 (1919–20). Fraser, T., and Yancey, H. F., *Trans. Amer. Inst. Mining Met. Engrs.*, 69, 447–69 (1923). Campbell, J. R., *Mining Congr. J.*, 14, 555–8 (1928). Chapman, W. R., and Mott, R. A., *The Cleaning of Coal,* Chapman & Hall, London, (1928), Chap. 21. MacLaren, W., *Colliery Guardian*, 144, 231–50 (1931). Tromp, K. F., *Glückauf*, 73, 121–31 (1937). Reed, W., and Grounds. A., *Colliery Eng.*, 23, 319–22 (1946). Hancock. R. T., *Colliery Eng.*, 24, 140–2, 191–3, 237–9 (1947). Anderson, W. W., AIME, *Trans.*, 187, 256–64 (1950). Belugou, P., and Ulmo, V., *Rev. ind. minérale,* 31, 13–23 (1950.Raineau, —, and Belugou, P., *Rev. ind. Minérale,* 31, 24–41 (1950). Belugou, P., and Vitoux, —, *Rev. ind. Minérale,* 31, 209–29 (1950). Lyons, O. R., AIME, *Trans.,* 193, 895–902 (1952).

The lack of a standard method of determining the efficiency probably results from numerous variables inherent in the task. The variables include the characteristics of the coal to be cleaned, the particular method of operation, the amount and nature of impurities to be removed, the percentage of near-gravity material, and the size range. This area of research would seem to be in need of Government activity or funding, and could be considered to be corollary research to the efforts to categorize the structure and composition of coals.

Finally, research on blending of coal and oil goes back approximately 50 years. An historic landmark of this research was a ship that crossed the Atlantic in 1932 using a coal and oil mixture.[11] The subcommittee was greatly interested in two documents discussed in the hearings, which showed the development of this technology. The first was a study by Pennsylvania State College on colloidal fuels and their development for industrial uses. The second was a patent on oil and water emulsion.

[11] See "Oversight Hearings, Coal Combustion R.D. & D. for Utility Power Plants and Industrial Uses," Subcommittee on Energy Research, Development, and Demonstration (Fossil Fuels), House Committee on Science and Technology, p. 239.

SECTION 2—USE AND PRODUCTION OF COAL

As can be seen by the accompanying figure 1, coal has had a very erratic production rate in the past. Twice before in our history, coal production reached approximately 600 million tons annually, only to plummet down to almost half that amount. Production reached over 550 million tons during the period 1925–1930, only to fall to approximately 300 million tons with the advent of the Great Depression. Again, in World War II, production reached over 600 million tons, only to gradually fall off to approximately 350 million tons by 1955.

However in an effort to stop the cycle, Congress made a significant policy decision in 1961 with the establishment of the Office of Coal Research. With this step and with increased funding for coal research, the Congress has encouraged the development of new uses and new markets for coal. The energy shortages early in this decade demonstrated the wisdom and foresight of that decision and reemphasized the necessity for developing coal. Congress, in passing the Energy Supply and Environmental Coordination Act, (P.L. 93–319, 88 U.S. Stat. 246) provided authority in section 2 of the Act for the Federal Energy Administration to order oil and natural gas burning electric generators to convert to the use of coal. This established a national policy of converting our greatest energy resource users to the use of our most abundant resource—coal. This authority was reaffirmed by Congress by the passage of Public Law 94–385, the Energy Conservation and Production Act of 1976. With this national policy determination, we now can reverse the past trends of coal production and instead of halving our production, we could double our production.

The Coal Reserve Base

The U.S. Geological Survey estimates that there are 3.6 trillion tons of coal within 3,000 feet of the surface in the United States and 4.0 trillion tons within 6,000 feet of the surface. (See table 1.) However, the U.S. Bureau of Mines estimates that only 434 billion tons of coal is considered minable with today's technology and economics; this amount is called the "demonstrated coal reserve base." (See table 2.) It should be remembered that only a certain percentage of the total (50–60 percent of underground mining by room and pillar techniques and up to 90% for surface mining) is recovered; the remainder is unavailable or lost during the mining process. The following table summarizes the demonstrated coal reserve base of the United States by coal rank and estimated total heating value.

74–260—77——4

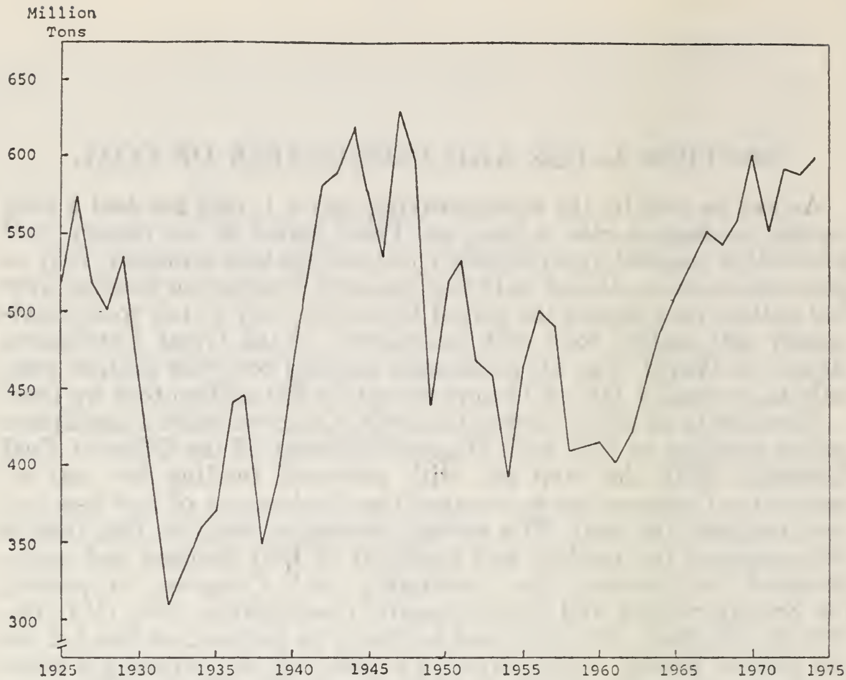


FIGURE 2–1.—Total bituminous coal production, 1925–74.

Source: National Coal Association statement by Carl E. Bagge before the Senate Committee on Public Works, June 10, 1975.

TABLE 2-1.—TOTAL ESTIMATED REMAINING COAL RESOURCES OF THE UNITED STATES, JANUARY 1, 1974

[In millions (10^6) of short tons. Estimates include beds of bituminous coal and anthracite generally 14 in or more thick, and beds of subbituminous coal and lignite generally 2½ ft or more thick, to overburden depths of 3,000 and 6,000 ft. Figures are for resources in the ground]

State	Overburden 0–3,000 feet							Overburden 3,000–6,000 feet—estimated additional hypothetical resources in deeper structural basins [1]	Overburden 0-6,000 feet—estimated total identified and hypothetical resources remaining in the ground
	Remaining identified resources, Jan. 1, 1974 (from table 2)					Estimated hypothetical resources in unmapped and unexplored areas [1]	Estimated total identified and hypothetical resources remaining in the ground		
	Bituminous coal	Subbituminous coal	Lignite	Anthracite and semianthracite	Total				
Alabama	13,262	0	2,000	0	15,262	20,000	35,262	6,000	41,262
Alaska	19,413	110,666	([2])	([3])	130,079	130,000	260,079	5,000	265,079
Arizona	[4] 21,234	([4])	0	0	21,234	0	21,234	0	21,234
Arkansas	1,638	0	350	428	2,416	[5] 4,000	6,416	0	6,416
Colorado	109,117	19,733	20	78	128,948	161,272	290,220	143,991	434,211
Georgia	24	0	0	0	24	60	84	0	84
Illinois	146,001	0	0	0	146,001	100,000	246,001	0	246,001
Indiana	32,868	0	0	0	32,868	22,000	54,868	0	54,868
Iowa	6,505	0	0	0	6,505	14,000	20,505	0	20,505
Kansas	18,668	0	([6])	0	18,668	4,000	22,668	0	22,668
Kentucky:									
Eastern	28,226	0	0	0	28,226	24,000	52,226	0	52,226
Western	36,120	0	0	0	36,120	28,000	64,120	0	64,120
Maryland	1,152	0	0	0	1,152	400	1,552	0	1,552
Michigan	205	0	0	0	205	500	705	0	705
Missouri	31,184	0	0	0	31,184	17,489	48,673	0	48,673
Montana	2,299	176,819	112,521	0	291,639	180,000	471,639	0	471,639
New Mexico	10,748	50,639	0	4	61,391	[7] 65,556	126,947	74,000	200,947
North Carolina	110	0	0	0	110	20	130	5	135
North Dakota	0	0	350,602	0	350,602	180,000	530,602	0	530,602
Ohio	41,166	0	0	0	41,166	6,152	47,318	0	47,318
Oklahoma	7,117	0	([6])	0	7,117	15,000	22,117	[8] 5,000	27,117
Oregon	50	284	0	0	334	100	434	0	434
Pennsylvania	63,940	0	0	18,812	82,752	[6] 4,000	86,752	[10] 3,600	90,352

See footnotes at end of table.

TABLE 2-1.—TOTAL ESTIMATED REMAINING COAL RESOURCES OF THE UNITED STATES, JANUARY 1, 1974—Continued

[In millions (10^6) of short tons. Estimates include beds of bituminous coal and anthracite generally 14 in or more thick, and beds of subbituminous coal and lignite generally 2½ ft or more thick, to overburden depths of 3,000 and 6,000 ft. Figures are for resources in the ground]

State	Overburden 0–3,000 feet: Remaining identified resources, Jan. 1, 1974 (from table 2): Bituminous coal	Subbituminous coal	Lignite	Anthracite and semianthracite	Total	Estimated hypothetical resources in unmapped and unexplored areas [1]	Estimated total identified and hypothetical resources remaining in the ground	Overburden 3,000–6,000 feet—estimated additional hypothetical resources in deeper structural basins [1]	Overburden 0–6,000 feet—estimated total identified and hypothetical resources remaining in the ground
South Dakota	0	0	2,185	0	2,185	1,000	3,185	0	3,185
Tennessee	2,530	0	0	0	2,530	2,000	4,530	0	4,530
Texas	6,048	0	10,293	0	16,341	[11] 112,100	128,441	([11])	128,441
Utah	[12] 23,186	173	0	0	23,359	[13] 22,000	45,359	35,000	80,359
Virginia	9,216	0	0	335	9,551	5,000	14,551	100	14,651
Washington	1,867	4,180	117	5	6,169	30,000	36,169	15,000	51,169
West Virginia	100,150	0	0	0	100,150	0	100,150	0	100,150
Wyoming	12,703	123,240	([2])	0	135,943	700,000	835,943	100,000	935,943
Other States [14]	610	[15] 32	[16] 46	0	6.88	1,000	1,688	0	1,688
Total	747,357	485,766	478,134	19,662	1,730,919	1,849,649	3,580,568	387,696	3,968,264

[1] Source of estimates: Alabama, W. C. Culbertson; Arkansas, B. R. Haley; Colorado, Holt (1975); Illinois, M. E. Hopkins and J. A. Simon; Indiana, C. E. Wier; Iowa, E. R. Landis; Kentucky, K. J. Englund; Missouri, Robertson (1971, 1973); Montana, R. E. Matson; New Mexico, Fassett and Hinds (1971); North Dakota, R. A. Brant; Ohio, H. R. Collins and D. O. Johnson from data in Struble and others (1971); Oklahoma, S. A. Friedman; Oregon, R. S. Mason; Pennsylvania anthracite, Arndt and others (1968); Pennsylvania bituminous coal, W. E. Edmunds; Tennessee, E. T. Luther; Texas, lignite, Kaiser (1974); Virginia, K. J. Englund; Utah, H. H. Doelling; Washington, H. M. Beikman; Wyoming, N. M. Denson, B. G. Glass, W. R. Keefer, and E. M. Schell; remaining States, by the author.

[2] Small resources of lignite included under sub-bituminous coal.

[3] Small resources of anthracite in the Bering River field believed to be too badly crushed and faulted to be economically recoverable (Barnes, 1951).

[4] All tonnage is in the Black Mesa field. Some coal in the Dakota Formation is near the rank boundary between bituminous and sub-bituminous coal. Does not include small resources of thin and impure coal in the Deer Creek and Pinedale fields.

[5] Lignite.

[6] Small resources of lignite in western Kansas and western Oklahoma in beds generally less than 30 in. thick.

[7] After Fassett and Hinds (1971) who reported 85,222,000,000 tons "inferred by zone" to an overburden depth of 3,000 ft in the Fruitland Formation of the San Juan basin. Their figure has been reduced by 19,666,000,000 tons as reported by Read and others (1950) for coal in all categories also to an overburden depth of 3,000 ft in the Fruitland Formation of the San Juan basin. The figure of Read and others was based on measured surface sections and is included in the identified tonnage recorded in table 2.

[8] Includes 100,000,000 tons inferred below 3,000 ft.

[9] Bituminous coal.

[10] Anthracite.

[11] Lignite, overburden 200–5,000 ft; identified and hypothetical resources undifferentiated. All beds assumed to be 2 ft thick, although many are thicker.

[12] Excludes coal in beds less than 4 ft thick.

[13] Includes coal in beds 14 in. or more thick, of which 15,000,000,000 tons is in beds 4 ft or more thick.

[14] California, Idaho, Nebraska, and Nevada.

[15] California and Idaho.

[16] California, Idaho, Louisiana, and Mississippi.

Source: Coal resources of the United States, Jan. 1, 1974, Geological Survey Bulletin 1412.

TABLE 2-2.—DEMONSTRATED COAL RESERVE BASE OF THE UNITED STATES

Coal rank	Reserves (billion tons) Underground	Surface	Total	Estimated total heat value quadrillion (Btu)
Bituminous	192	41	233	6, 100
Subbituminous	98	67	165	2, 800
Lignite	0	28	28	400
Anthracite	7	<½	7+	200
Total	297	137—	434—	9, 500

Source: U.S. Bureau of Mines, "Demonstrated Coal Reserve Base of the United States on Jan. 1, 1974," June 19, 1974, table 1.

The following maps (figure 2) show the location of the nation's coal fields and the mining regions. Approximately two-thirds of the coal reserve base is expected to be mined by underground methods and the other one-third by surface methods.

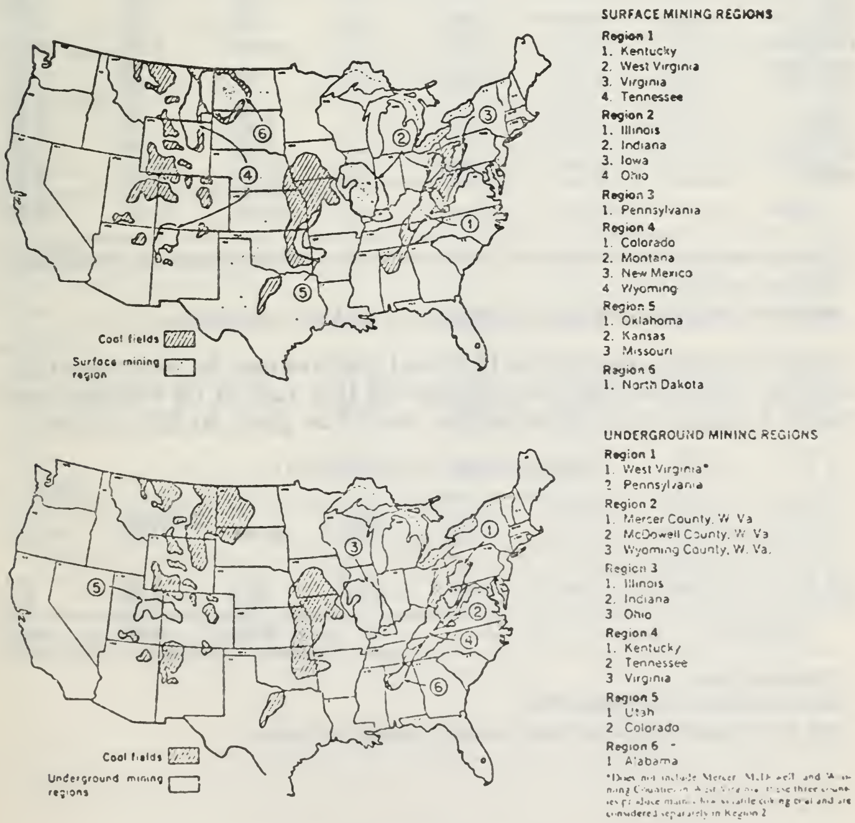


FIGURE 2–2.—Coal fields of the United States.

Source: 1974 Keystone Coal Industry Manual.

TABLE 2-3.—DEMONSTRATED COAL RESERVE BASE[1] OF THE UNITED STATES ON JAN. 1, 1974, BY METHOD OF MINING

[In millions of short tons]

State	Potential mining method		
	Underground	Surface	Total
Alabama	1,798	1,184	2,982
Alaska	4,246	7,399	11,645
Arizona		350	350
Arkansas	420	263	665
Colorado	14,000	870	14,870
Georgia	1		1
Illinois	53,442	12,223	65,665
Indiana	8,949	1,674	10,623
Iowa	2,885		2,885
Kansas		1,388	1,388
Kentucky, east	9,467	3,450	12,917
Kentucky, west	8,720	3,904	12,624
Maryland	902	146	1,048
Michigan	118	1	119
Missouri	6,074	3,414	9,488
Montana	65,165	42,562	107,727
New Mexico	2,136	2,258	4,394
North Carolina	31	(2)	31
North Dakota		16,003	16,003
Ohio	17,423	3,654	21,077
Oklahoma	860	434	1,294
Oregon	1	(2)	1
Pennsylvania	29,819	1,181	31,000
South Dakota		428	428
Tennessee	667	320	987
Texas		3,272	3,272
Utah	3,780	262	4,042
Virginia	2,971	679	3,650
Washington	1,446	508	1,954
West Virginia	34,378	5,212	39,590
Wyoming	27,554	23,674	51,228
Total	297,235	136,713	433,948

[1] Includes measured and indicated categories as defined by the USBM and USGS and represents 100 percent of the coal in place.
[2] Less than 1,000,000 tons.

Source: Demonstrated coal reserve base of the United States on Jan. 1, 1974, Bureau of Mines.

Use of tonnage figures for U.S. coal reserves may be somewhat misleading. The subcommittee emphasized this fact in its hearings and stressed that further consideration should be given to Btu content.

DEMONSTRATED COAL RESERVE BASE[1]

	Billion tons	Percent	Quadrillion Btu	Percent
East	202.3	46.3	5,000	52.1
West	234.4	53.7	4,600	47.9
Total, national	436.7	100.0	9,600	100.0

[1] Includes anthracite.

Source: 1976 National Energy Outlook, FEA.

Note: As can be seen, the percentage of energy availability is reversed in this analysis.

One of the most important criteria for the marketability of coal in the future is the amount of sulfur. The following tables 4 and 5 show a breakdown of the coal reserve base by State, by the percentage of sulfur in the coal, and by mining methods.

TABLE 2-4.—RESERVE BASE OF EASTERN BITUMINOUS COAL IN COALBEDS GREATER THAN 28 IN THICK TO A MAXIMUM DEPTH OF 1,000 FT, BY MINING METHOD AND SULFUR CONTENT

[In millions of short tons]

State and mining method	Sulfur content, weight (percent)				
	≦1	1.1 to 3	>3	Unknown	Total [2]
Alabama:					
Deep	589.32	1,016.74	14.79	176.24	1,798.09
Strip	35.35	83.17	1.56	36.65	157.24
Georgia:					
Deep	.33	0	0	.17	.50
Strip	0	0	0	0	0
Illinois:					
Deep	1,034.68	5,848.37	33,647.64	12,908.44	53,441.86
Strip	60.37	1,493.04	9,321.32	1,347.78	12,222.86
Indiana:					
Deep	443.54	2,746.61	4,355.12	1,402.45	8,948.49
Strip	105.25	559.23	907.20	101.56	1,674.08
Kentucky, eastern:					
Deep	5,042.70	2,391.88	212.67	1,814.03	9,466.48
Strip	1,515.65	929.90	86.82	915.32	3,450.16
Kentucky, western:					
Deep	0	386.58	7,226.36	1,107.11	8,719.89
Strip	.22	177.83	2,017.45	1,708.69	3,904.02
Maryland:					
Deep	106.45	623.94	171.18	0	901.91
Strip	28.56	66.59	16.24	34.57	146.30
Michigan:					
Deep	4.59	84.93	20.78	7.03	117.64
Strip	0	.49	.05	0	.56
North Carolina:					
Deep	0	0	0	31.25	31.25
Strip	0	0	0	.37	.37
Ohio:					
Deep	115.45	5,449.88	10,109.36	1,754.09	17,423.26
Strip	18.87	990.96	2,524.87	117.93	3,653.89
Pennsylvania:					
Deep	981.15	16,013.46	3,568.14	2,215.60	22,788.94
Strip	55.45	717.21	231.52	83.57	1,091.07
Tennessee:					
Deep	139.29	369.98	101.37	53.87	667.13
Strip	65.54	163.19	55.22	34.12	319.59
Virginia:					
Deep	1,676.05	945.42	12.03	198.31	2,833.24
Strip	411.58	218.06	2.06	46.69	679.24
West Virginia:					
Deep	11,086.60	12,583.41	6,552.88	4,142.92	34,377.77
Strip	3,005.46	1,422.82	270.40	509.55	5,212.02
Total:					
Deep	21,220.15	48,461.20	65,992.32	25,811.51	161,516.45
Strip	5,302.30	6,822.49	15,434.71	4,936.90	32,511.40

[1] Includes only measured and indicated reserves.
[2] Distribution may not add to total because of rounding.

TABLE 2-5.—THE RESERVE BASE OF COALS OF THE WESTERN UNITED STATES BY MINING METHOD AND SULFUR CONTENT

[In millions of short tons]

State and mining method	Sulfur content, weight (percent)				
	<1.0	1.1-3.0	>3.0	Unknown	Total
Alaska:					
Deep	4,080.8	163.3	0	0	4,246.4
Strip	7,377.8	21.0	0	0	7,399.0
Arizona: Strip	173.2	176.7	0	0	350.0
Arkansas:					
Deep	43.4	310.3	29.2	19.1	402.4
Strip	37.9	152.9	17.1	55.2	263.3
Colorado:					
Deep	6,751.3	640.0	47.3	6,547.4	13,999.2
Strip	724.2	146.2	0	0	870.0
Iowa: Deep	1.6	226.7	2,105.9	549.2	2,884.9
Kansas: Strip	0	309.3	695.6	383.2	1,388.1
Missouri:					
Deep	0	134.2	3,590.2	2,350.5	6,073.6
Strip	0	47.8	1,635.8	1,730.0	3,413.7
Montana:					
Deep	63,464.4	1,939.9	456.2	0	65,834.3
Strip	38,182.5	2,175.4	46.4	2,166.7	43,562.0
New Mexico:					
Deep	1,894.4	214.1	.8	27.5	2,136.5
Strip	1,681.1	579.4	0	0	2,258.3
North Dakota: Strip	5,389.0	10,325.5	268.7	15.0	16,003.0
Oklahoma:					
Deep	154.5	238.4	202.6	264.3	860.1
Strip	120.5	88.2	38.8	186.2	434.1
Oregon:					
Deep	1.0	0	0	0	1.0
Strip	.5	.3	0	0	.9
South Dakota: Strip	103.1	287.9	35.9	1.0	428.0
Texas: Strip	659.8	1,884.7	284.1	444.0	3,271.9
Utah:					
Deep	1,916.2	1,397.6	6.8	460.3	3,780.5
Strip	52.3	149.2	42.6	18.0	262.0
Washington:					
Deep	431.0	957.7	13.2	42.9	1,445.9
Strip	172.5	307.7	25.8	2.2	508.1
Wyoming: Deep	20,719.1	4,535.0	1,275.6	2,955.0	29,490.8
Strip	13,192.9	10,122.4	425.5	105.3	23,845.3
Total [1]:					
Deep	99,457.7	10,757.2	7,727.8	13,216.2	131,155.6
Strip	67,866.8	26,774.3	3,516.3	5,106.8	103,256.8
Grand total	167,324.5	37,531.5	11,244.1	18,323.0	234,412.4

[1] Distribution may not add to total because of individual rounding.

It should also be noted that much of the eastern low sulfur coal that is readily minable is now reserved for the metallurgical and export markets.

One of the final, but not least important considerations in the development of new coal fields is the recoverability of the resource. The two most important factors to be considered here are the bed depth and seam thickness. Although both are major economic factors, bed depth is often the more important. In 1965, the average depth of coal being mined from the surface was 55 feet and the average seam thickness was 5.2 feet, giving a ratio of overburden to seam thickness of roughly 10:1. This ratio has been increasing as mining technologies have advanced, and a 30:1 ratio is now suggested as reasonable for the 1970's.

For the development of our coal fields and managing the resource, the Bureau of Mines divides the Nation up into four provinces—

Eastern, Interior, Northern, and Rocky Mountain. The Eastern province is comprised of three regions: Appalachian, Pennsylvania Anthracite, and Atlantic Coast. This province has more than eighty percent of the U.S.'s remaining identified high-ranked bituminous coal. The sulfur content of eastern coals varies considerably; approximately 65 percent of the province's identified resources have a sulfur content of more than 1 percent. Surface water supplies in the province are abundant, and precipitation averages between 35 and 50 inches per year.

The Interior Province is comprised of four regions: Northern, Eastern, Western, and Southwestern. Most of the coal in this region is bituminous, a small amount of anthracite in Arkansas being the exception. Except for low-volatile coal found in Arkansas and eastern Oklahoma, bituminous is highly volatile. The moisture content is generally low except for coals in the northern part of the province, and sulfur content tends to be high, generally in excess of three percent. Although most of the province is well supplied with water, competition for its use is generally keen. The annual rainfall ranges from about 32 to 48 inches.

The Northern Great Plains Province is composed of six regions, the two largest being Fort Union and Powder River. Most of the coal within the province is relatively low in rank, with lignite in the Fort Union region and thick deposits of sub-bituminous in the Powder River region. Near the edge of the Rocky Mountains, the coal is somewhat higher in rank. The moisture and volatile matter content of both Fort Union and Powder River coals are relatively high and, as indicated by their low rank, both tend to be low in energy value. Water supplies are not abundant, and most of the surface water is found in the northern Missouri River drainage basin. Much of this water comes from run-off from the mountains to the west. The average annual run-off ranges from less than 1 inch to 10 inches.

The Rocky Mountain province is composed of eight regions, the largest of which are the Green River, Uinita, and San Juan River. The Province has the greatest variety in ranks and geologic setting of any province in the United States. Moisture content tends to be low and volatile matter content relatively high. Heating values range from 5,000 to more than 14,000 Btu's per pound. Sulfur content is generally low with almost 90 percent of identified resources having a sulfur content of 1 percent or less. Except for the high mountains, precipitation averages less than 16 inches per year, and large semidesert areas receive less than 8 inches. As a consequence, water is almost universally scarce in the province.

Ownership

By far the largest single owner of the coal reserves in the United States is the Federal Government. The Federal Government owns approximately 48 percent of all coal lands located in Alaska, Colorado, Montana, North Dakota, Oklahoma, Utah and Wyoming. Federal ownership in these states ranges from 4 percent in Oklahoma to 97 percent in Alaska. In contrast, the major coal lands in the eastern and western U.S. are privately owned.

74-260—77——5

With regard to private ownership, a study prepared by Mitre Corporation for the FEA, *Analysis of Steam-Coal Sales and Purchases*, concluded that the coal industry was top heavy; the top 15 companies control 47 percent of the market; the other 5,000 companies share the rest. However, the large coal companies are limited in their flexibility and their abillity to take advantage of fluctuations in coal prices. The Mitre study showed that these companies have 95–100 percent of their coal committed to long-term contracts. For the small companies interviewed by Mitre, the rate was 10–20 percent. These long-term contracts are traditionally between the coal producer and the public utilities, and usually are drawn up for periods of thirty years. It should also be noted that many utilities themselves own coal reserves. For example, the Tennessee Valley Authority presently owns four tracts of minerable coal reserves: Red Bird, in Eastern Kentucky, Koppers in Tennessee, Franklin County in Illinois, and Breckenridge in Western Kentucky. TVA is presently receiving coal from two of these tracts.

Recently, public attention has been focused on the acquisition of coal companies by some of the major oil companies, which has been occurring over the past decade. Weekly Energy Report stated [1] that in many cases the recently acquired coal production divisions of certain oil companies meant the difference between loss and profit for those companies, citing Standard Oil of Ohio and Occidental Petroleum Company. The following table [2] shows the ownership of coal companies by some of the major domestic oil companies and their relative productions. The next table [3] shows the production by coal companies and their parent companies from 1964 to 1974. The original table provides the 7-company output as a percent total for the entire 10 years; however, by eliminating the production levels for the coal companies, in the years before acquisition by an oil company, the actual share of coal production by the oil firms can be seen. This is illustrated on the last line of the table which has been added by the subcommittee. That line illustrates the steadily rising percentage of coal production which is controlled by some oil firms.

[1] Weekly Energy Report, August 4, 1975, p. 5.
[2] Submission of Exxon Co., U.S.A. (A Division of Exxon Corp.), before the House Judiciary Subcommittee on Monopolies and Commercial law, September 11, 1975.
[3] Id.

TABLE 2–6.—OIL COMPANY PARTICIPATION IN COAL PRODUCTION, 1974

	Million tons	Percent of U.S. output	Rank
Continental Oil (Consolidation Coal)	51.8	8.6	2
Occidental Petroleum (Island Creek)	20.8	3.5	3
Ashland-Hunt (Arch)	13.9	2.3	8
Sohio (Big Ben)	9.5	1.6	10
Gulf Oil (Pittsburg & Midway)	7.5	1.3	13
Exxon	2.5	.4	37
Belco (Hawley Fuels)	1.3	.2	61
Total of oil companies	107.3	17.9	
Total U.S. coal output	601.0		

Source: Keystone News Bulletin, vol. 33, Nos. 2 and 3, Feb. 26 and Mar. 25, 1975.

TABLE 2-7.—OIL FIRM COAL PRODUCTION

[In millions of tons]

Coal company	Parent company	1964	1965	1966	1967	1968	1969	1970	1971	1972	9713	1974
Consolidation & Affiliated Cos	Continental	45.4	48.6	[1] 51.4	56.5	59.9	60.9	64.1	54.8	64.9	60.5	51.8
Island Creek	Occidental	21.2	20.6	23.7	25.9	[1] 25.9	30.3	29.7	22.9	22.6	22.9	20.8
Old Ben	Standard of Ohio	5.1	6.3	9.9	10.3	[1] 9.9	12.0	11.7	10.5	11.2	10.8	9.5
Pittsburg & Midway	Gulf	[1] 7.1	8.2	8.8	9.0	9.2	7.6	7.8	7.1	7.7	8.1	7.5
Hawley Fuels	Belco	1.0	2.1	1.9	1.7	[1] 1.5	1.7	1.8	1.4	1.6	1.5	1.3
Arch Minerals	Ashland	2.3	5.1	6.8	7.5	7.0	6.8	6.3	[1] 7.2	11.2	12.5	13.9
Monterey Coal	Exxon							0.3	1.2	2.0	2.7	2.5
7-company total		82.1	90.9	102.5	110.9	113.4	119.3	121.7	105.1	121.2	119.0	107.3
Industry total		487.0	512.1	533.9	552.5	545.2	560.5	602.9	552.2	595.4	591.7	601.0
7-company output as percent of total		16.9	17.8	19.2	20.1	20.8	21.3	20.2	19.0	20.4	20.1	17.9
Oil firm coal production [2] as percent of total		1.5	1.6	11.3	11.8	19.5	20.1	19.1	19.0	20.4	20.1	17.9

[1] Year acquired by oil company.

[2] This line is a committee addition.

Source: Keystone Coal Industry Manual (McGraw-Hill), various years.

COAL PRODUCTION LEVELS

In the last ten years, the total production of coal has risen slowly. By 1970 it reached 603 million tons, an increase of 18 percent over the 1965 level, or a little over 3 percent per year. From 1973 to 1975, however, U.S. coal production has held relatively constant at 590–600 million tons. (Preliminary reports from the Bureau of Mines shows a level of 665 million tons for 1976.)

The following table 8 shows production for 1971 and 1973 by state.

TABLE 2-8.—UNDERGROUND AND SURFACE BITUMINOUS COAL AND LIGNITE PRODUCTION, BY STATE

		1971		1973	
	1973 tonnage (millions)	Percent surface	Percent underground	Percent surface	Percent underground
Alabama	19.8	62	38	60	40
Alaska	.7	100	0	100	0
Arizona	3.0	100	0	100	0
Arkansas	.5	85	15	100	0
Colorado	6.2	38	62	46	54
Illinois	61.5	50	50	47	53
Indiana	25.2	83	17	97	3
Iowa	.9	58	42	55	45
Kansas	1.1	100	0	100	0
Kentucky	127.0	55	45	50	50
Maryland	1.6	89	11	97	3
Missouri	5.0	100	0	100	0
Montana	10.0	100	0	100	0
New Mexico	9.3	88	12	89	11
North Dakota	7.4	100	0	100	0
Ohio	45.3	75	25	64	36
Oklahoma	2.6	92	8	97	3
Pennsylvania	76.6	39	61	40	60
Tennessee	9.0	62	38	47	53
Utah	5.1	0	100	0	100
Virginia	33.9	29	71	31	69
Washington	3.2	97	3	99	1
West Virginia	115.2	22	78	17	83
Wyoming	13.6	98	2	95	5
Other States	6.9			100	0
Total	591.0	50	50	51	49

Source: U.S. Bureau of Mines.

NEW POWER PLANTS, COAL DEMAND

By far, the largest users of coal in the United States are public utility electric powerplants. The present level (approximately 71 percent of coal consumption) is a significant change from the earlier part of the century; for example, in 1935 coal consumption for generation purposes stood at only 9 percent. This fact is illustrated by the following table 9.[4]

[4] "Bituminous Coal Data," National Coal Assn.; U.S. Dept. of the Interior.

TABLE 2-9.—YEARLY CONSUMPTION, BY CONSUMER CLASS, OF BITUMINOUS COAL

[In millions of tons]

Year	Electric power utilities	Bunker foreign trade	Railroads (class 1)	Beehive coke plants	Oven coke plants	Steel and rolling mills	Cement mills	Other manufacturing and mining industries	Retail dealer deliveries	Total
1935	30.9	2.3	77,1 9	1.5	49.0	16.5	3.5	94.5	80.4	356.3
1940	49.1	3.0	85,130	4.8	76.5	14.1	5.6	107.8	84.6	430.9
1945	71.6	3.2	125,120	8.1	87.2	14.2	4.2	126.5	119.2	559.5
1950	88.2	2.0	60,969	9.1	94.7	10.8	7.9	95.8	84.4	454.2
1955	140.5	1.5	15,473	2.9	104.5	7.3	8.5	89.6	53.0	423.4
1960	173.8	.9	2,101	1.6	79.3	7.3	8.2	76.4	30.4	380.4
1961	179.6	.8	(1)	1.5	72.3	7.4	7.6	77.2	27.7	374.4
1962	190.8	.7	(1)	1.3	72.9	7.3	7.7	78.7	28.1	387.7
1963	209.0	.7	(1)	1.6	76.0	7.4	8.1	82.7	23.5	409.2
1964	223.0	.7	(1)	2.0	86.7	7.3	8.7	82.9	19.6	431.1
1965	242.7	.7	(1)	2.7	92.0	7.4	8.9	85.6	19.0	459.1
1966	264.2	.6	(1)	2.4	93.5	7.1	9.1	89.3	19.9	486.2
1967	271.7	.5	(1)	1.4	90.9	6.3	8.9	83.5	17.0	480.4
1968	294.7	.4	(1)	1.3	89.4	5.6	9.4	82.6	15.2	498.9
1969	308.4	.3	(1)	1.2	91.7	5.5	(3 4)	85.3	14.6	507.2
1970	320.4	.3	(1)	1.4	94.5	5.4	(4)	82.9	12.0	517.1
1971	326.2	.2	(1)	1.3	81.5	5.5	(4)	68.6	11.3	494.8
1972	348.6	.2	(1)	1.1	86.3	4.8	(4)	67.1	8.7	512.7
1973	386.9	.1	(1)	1.2	92.3	6.4	(4)	60.8	8.2	556.0
1974 [2]	391.0	.1	(1)	1.1	90.0	6.4	(4)	60.0	8.0	551.3

[1] Canvass discontinued.
[2] Preliminary.
[3] 1969 consumption figures were revised. No revised breakdown between "Cement mills" and "Other manufacturing and mining industries" was available.
[4] Included with "Other manufacturing and mining industries" 1969–74.

Sources: "Bituminous Coal Data," National Coal Association; U.S. Department of the Interior.

However, despite the predominance of electric generation as a consumer of coal, the converse is not also true. Coal has been steadily declining in its share of the electric generation market. The tendency to use boiler fuels other than coal has accelerated, particularly in the 1960's. Most new fossil fired plants were designed for oil and natural gas, and in addition, from 1965 on an increasing number of existing boilers were converted from coal to oil. Between 1965 and 1972, 398 boilers with a total name plate capacity of 28,785 megawatts were converted.

In the early 1960's, most of these conversions from coal to oil were based on economics. It was cheaper to import residual oil to burn in east coast power plants than to ship coal from Appalachian areas. In some cases, particularly in urbanized areas later in the decade, air pollution regulations motivated the switch. As the Clean Air Act Amendments of 1970 made their way through Congress, environmental concerns became more important and the pace of conversions quickened, peaking in 1971 and 1972.

Despite the legislation which motivated electric powerplants to switch from coal to oil, coal also appeared uneconomic. Estimates

of 1972 capital costs per kilowatt of installed capacity for plants with no stack gas cleaning are $180 for coal, $150 for oil, and $100 for gas.[6]

Clearly, if coal is to play a major role in our future energy supplies, new research and technological development must occur in order to improve the position of coal.

Despite the unfavorable environmental and cost characteristics of coal fired generating plants, the National Coal Association predicts a significant increase in the number of coal fired electric generation plants in the next five years. The NCA has prepared a study of announced electric generating units scheduled to go on-stream during the remainder of this decade. The conclusions of this study are in the following table 10. The announced coal fired units that will come onstream during this period will require 203.5 million tons of coal annually. Furthermore, recently announced conversion orders from FEA would increase the demand for coal by 1978 to 16.2 million tons annually. This is accomplished gradually in steps beginning with the demand of 0.7 million tons in 1975, 4 million tons in 1976, and 13.6 million tons in 1977.

[6] Energy Alternatives: A comparative analysis, by the Science and Public Policy Program, University of Oklahoma, Norman, Oklahoma, p. 12–21. The authors of this report note that present construction prices have increased significantly. The AEC estimated capital costs at $660KW for nuclear and $550KW for coal in 1974, just 2 years later.

TABLE 2-10.—LOCATION OF COAL FIRED GENERATING UNITS COMING ONSTREAM 1975–79

State	Number of units	Associated capacity (megawatts)
Connecticut	0	----------
Maine	0	----------
Massachusetts	0	----------
New Hampshire	0	----------
Rhode Island	0	----------
Vermont	0	----------
New England, total	0	----------
New Jersey	0	----------
New York	0	----------
Pennsylvania	4	3,125
Middle Atlantic, total	4	3,125
Illinois	7	3,315
Indiana	9	5,049
Michigan	2	140
Ohio	7	3,715
Wisconsin	3	1,373
East North-central, total	28	13,592
Iowa	4	2,045
Kansas	4	2,305
Minnesota	2	1,440
Missouri	5	2,459
Nebraska	3	1,316
North Dakota	4	1,899
South Dakota	1	440
West North-central, total	23	11,904
Delaware	1	400
District of Columbia	0	----------
Florida	1	445
Georgia	3	2,856
Maryland	0	----------
North Carolina	3	2,520
South Carolina	2	630
Virginia	0	----------
West Virginia	3	2,576
South Atlantic, total	13	9,427
Alabama	4	1,720
Kentucky	4	1,720
Mississippi	3	860
Tennessee	0	----------
East south-central, total	11	4,300
Arkansas	4	4,229
Louisiana	2	1,125
Oklahoma	4	2,161
Texas	17	10,054
West south-central, total	27	15,769
Arizona	8	3,156
Colorado	6	2,070
Idaho	0	----------
Montana	4	2,106
Nevada	3	500
New Mexico	2	820
Utah	2	800
Wyoming	5	2,330
Mountain total	30	11,782
California	0	----------
Oregon	0	----------
Washington	0	----------
Pacific total	0	----------
National total	136	69,898

Source: Statement by Carl E. Bagge of the NCA before the Senate Committee on Public Works, June 10, 1975.

SECTION 3—FLUIDIZED BED BOILERS

HISTORY

The hearing testimony revealed that there had been no significant breakthroughs in coal combustion technology since the late 1920's. While there apparently had been a gradual improvement in coal combustion technology and power generation efficiency, there had been nothing in the way of a new technology or dramatic change in this field. The only thing on the horizon was the atmospheric fluidized bed boilers which will not be commercially operative until about 1980–85.

Members of the subcommittee expressed concern that the research and development program on fluidized bed technology being conducted by ERDA, has only recently been accorded the high priority which it deserves. The 30 MWe fluidized bed boiler project, being constructed by ERDA at Rivesville, West Virginia was begun in October, 1972, and is actually an extension of a program which began in 1965. Witnesses testified that there had been an 18-month delay in the projected construction time due to longer order times than normal, in this inflationary period, and because of changes in West Virginia's environmental standards. While such delays are not unusual, some precautionary planning can be made. At the time this report was written, ERDA was requesting authorization for a 200 MWe fluidized bed combustion demonstration plant.

However, despite the fact that the Government's program was started only a decade prior, the fluidized bed concept has been utilized for some time.

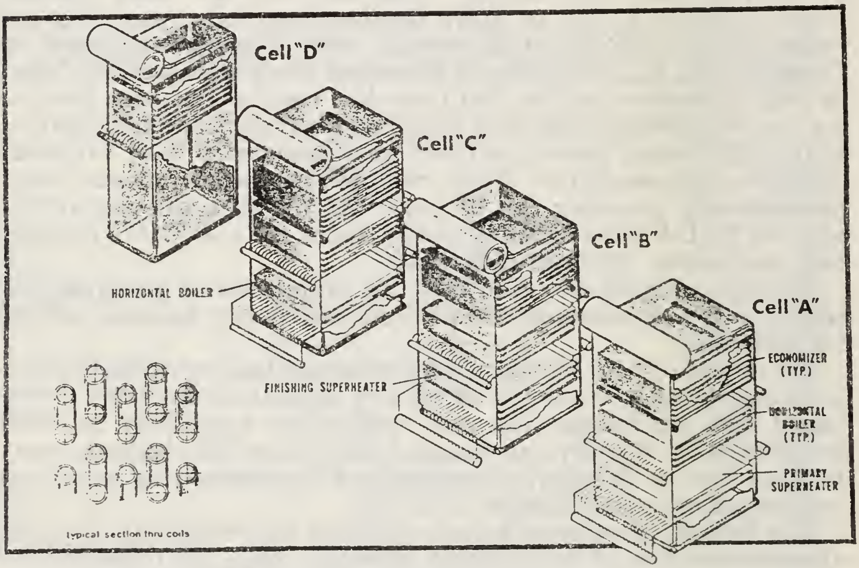
The technology for fluidized bed combustion has its origins in petroleum engineering; a number of refinery operations are based on fluidized bed technology. The coal combustion technology is really building on oil industry knowledge of fairly large fluid beds of twenty to forty feet in diameter, where much of the engineering experience has been gained over the years.

The Federal government's program began approximately five years after the creation of the OCR. In February, 1965, the Office of Coal Research awarded the construction firm Pope, Evans and Robbins a contract to build and operate a small atmospheric fluidized bed boiler. The objective of the program was to attempt to meet rigorous air pollution standards while burning high-sulfur coals and simultaneously eliminate ash, fouling, and slagging problems. This small pilot plant accomplished these goals and also indicated the promise of improved power plant efficiency and cleanliness when burning chars, anthracite, or conventional coal, and the possibility of eliminating the need for pulverization of the coal feed.[1]

[1] See "Study of the Characterization and Control of Air Pollutants from a Fluidized Bed Boiler—The SO_2 Acceptor Process" by J. S. Gordon, et al; Pope, Evans and Robbins, Inc.—EPA-R2-72-021, July 1972.

Pope, Evans and Robbins was awarded another OCR contract in May, 1972, to perform additional experimental work on a small (0.5 Mw) unit. Four types of fuels were burned to demonstrate the feasibility of fluidized bed combustion and to examine the effect of lignite, high-sodium content. One of the major results of this contract was to show that sulfur-oxide emissions were reduced to levels well below the emissions standards of existing and proposed Federal and local regulations. The project also indicated that the addition of small quantities of common salt to the fluidized bed was a useful method for increasing limestone utilization.

The Office of Coal Research also awarded a contract in October, 1972, to design, construct, and operate a 30 MWe size multicell fluidized bed boiler under practical utility conditions. Steam pressure and temperature conditions of the boiler were designed to meet the requirements of the site at which the boiler was installed—the power plant of the Monongahela Power Co. at Rivesville, W. Va. The Foster-Wheeler Energy Corp. was awarded the contract for the construction of this boiler. The following figure is a schematic diagram of this facility.



Fluidized Bed Steam Generator Multicell Demonstration Unit — Indicating the heat transfer surface arrangement.

FIGURE 3–1

During 1974, shop fabrication of the 30 MWe boiler was completed in the field direction work and the Monongahela Power Co. powerplant was started. Auxiliary systems and plant general construction including boiler and plant controls, and laboratory construction work was also started in 1974. Boiler installation was completed during 1975 and operations started in 1976.

Atmospheric Fluidized Bed

This type of fluid bed combustor seems to offer the greatest potential for early commercialization, possibly by 1979. It also appears to be very attractive for industrial use and for utility applications because it improves combustion efficiencies, significantly reduces emission levels, has a very attractive capital costing, and can use the cheaper, high-sulfur coal.

The subcommittee received testimony that the costs of the fluidized bed boiler, when compared to a conventional boiler with stack scrubbing, were very favorable. For power plants operated in a base-load mode (average annual capacity factor about 65 percent), the cost of power generation is the same for the two types of boilers. EPRI supplied the following table of estimated costs:

Boiler type	Power plant capital costs dollars per kilowatt	Power costs, cents per kilowatt hour
Atmospheric fluidized bed	530	3.1
Conventional boiler with stack gas scrubbing	590	3.1

The above capital costs for complete power plants are based on 1975 construction costs and include engineering fees, contingency, interest during construction and start-up costs. Power costs are based on coal costs of $1/MMBTU (about $21/short ton), and limestone costs of $9/short ton.

The capital costs of the fluidized bed plant are about 10% lower than for the conventional plant. This cost advantage is largely due to the fact that the fluidized bed boiler is much smaller than a conventional boiler with a similar rating, due to the higher heat-transfer capability of the fluidized bed. Some cost saving is also anticipated from shop fabrication of modular fluidized bed boilers against more expensive field fabrication of conventional boilers.

Operating costs for the fluidized bed plant may be higher however since limestone consumption is estimated to be three to four times greater than for the stack gas scrubbing system. First of all, the unit size is smaller because fluid bed combustion can increase volumetric heat release rates by as much as an order of magnitude above rates realized in present combustors. Overall heat transfer rates are improved correspondingly. Also, boiler tubes spacing can therefore be much closer than in conventional fixed-bed boilers, providing unit compactness.

Emission control for fluidized-bed boilers centers in the combustion zone. Sized coal is burned in a fluidized bed of inert ash and limestone or dolomite. The limestone or dolomite reacts with SO_2 to form a solid sulfate material. Owing to increased thermal efficiencies, fluid-bed boilers can be operated at bed temperatures lower than conventional boilers thus inhibiting the formation of nitrogen oxides. An atmospheric pressure coal-fired fluidized-bed boiler having a capacity of 5,000 pounds of steam per hour has been successfully operated at furnace temperatures of approximately 1,600 degrees Farenheit. It has

demonstrated that all types of coal can be burned in an environmentally acceptable manner.

One problem that has not been solved is the matter of handling the limestone sorbent after it is no longer active. There are two approaches being explored at the present time. One is to collect the limestone and to simply dispose of it in an acceptable manner, many options of which are being pursued. Because it comes out dry, it presents no material handling problem, as opposed to the wet sludge which is the byproduct of stack gas treatment. The other approach being pursued is to regenerate or reactivate the limestone, recirculate it, and remove the sulfur in the elemental form for disposal. The Subcommittee received testimony that a number of companies were investigating the use of limestone sorbent as land-fill material. It is attractive to them because it is dry, only partially sulfated, and contains ash and other aggregate material. Conversion to an acceptable land-fill material would be easier with this sort of partially-sulfated limestone than with the wet sludge from scrubbers. ERDA has also supplied samples of the limestone sorbent to a few agricultural firms for use as a soil conditioner. In 1974, peanuts were successfully grown using this spent limestone in place of lime and other nutrients, that are required in the soil.

Members of the Subcommittee noted that the disposal of these large volumes of waste was a significant environmental problem. Agency officials who testified felt that these problems were being dealt with and can be solved.

Another dimension to this disposal problem is the investigation of alternative sorbents for the fluidized bed boiler, such as dolomite in addition to limestone as a natural material. Also, the Argonne National Laboratory is investigating creating a synthetic material which contains lime, that could be regenerated without losing the lime. It is in the form of p ellets that could be easily recirculated and re-used without loss of lime or any of the other active ingredients.

The members of the Subcommittee were impressed by the versatility of the fluidized bed concept. The fluidized bed boiler can burn a number of materials. It can burn culm, which is a waste material with anthracite in it, or gob, which is a similar waste material but with bituminous coal in it. ERDA is also testing chars which are a product of the gasification process. The fluidized bed must be designed for a specific sized fuel material. Variation in size of the fuels or wastes to be burned would mean that a fluidized bed would have to be re-equipped to take various sizes. The size problem arises in the dynamics of the bed. The gas in the bed supports particles that are not all identical, but of a fairly uniform size. Very fine particles fly off the top and are captured by the precipitator, while the larger particles would rapidly settle to the bottom and not be combusted. Therefore where particle size is uniform with deminimus variations, the problem is manageable. However, where there is a broader range of sizes, the problems accelerate beyond control.

Pressurized Fluidized Bed Boilers

This is the next generation of technology for fluidized beds and will result in considerable increases in thermal and design efficiencies.

The basic technology for the pressurized system is similar to the atmospheric system except that the coal and bed material must be injected into a pressurized combustion chamber and the process converted to a combined cycle system.

The higher through-put capability of pressurized systems further reduces the size of the combustion unit. The use of combined cycle systems (steam and gas turbine) will increase the overall plant efficiency (coal to power) from 39 percent for atmospheric boilers to 43 percent for the pressurized systems, with a potential of exceeding 50 percent.

Objectives for the pressurized program are similar to the atmospheric, except that developmental problems are greater and more complex, and the first commercial units would be at least 2 years further down the road. Limited tests of American coals were performed in a 5–6 atmospheres pressure test unit at Leatherhead, England and have shown that this approach is feasible from a technological standpoint.

For the past 7 years, Combustion Power Co., Inc. of Menlo Park, Calif. has been conducting a research and development program under the sponsorship of EPA, to convert the heat energy of solid wastes to electrical energy through the use of its pressurized fluidized bed and gas turbine system. With the cooperation of EPA, OCR contracted with Combustion Power in June of 1973 to conduct a research and development program to demonstrate the combustion of high-sulfur coal in this system.

Under the current contract, CPC has conducted evaluations of coal combustion in a model of this combination combustor, using caking and non-caking high-sulfur coals. The caking coal used was lower Kittanning seam; the non-caking coal used was Illinois No 6. The coals were tested at various pressures and temperatures.

CPC then modified the fluidized bed system to provide the capability for coal and dolomite storage and feeding. This modified system became the process development unit. Long-duration tests were conducted in this process development unit, using the data from the model experiments to determine and minimize exhaust emission levels of noxious gases and particulates. In addition, candidate turbine blade materials and coatings were installed in the turbine rotors and stators to evaluate corrosion and erosion effects.

The results of the test indicated that the dolomites used were effective in suppressing SO_2, the relative effects of superficial velocities and bed temperatures was slight, and the optimum calcium-sulfur ratio was 1.5. Limestone was consistently ten to fifteen percent less effective than dolomite under all test conditions. The most serious problem encountered during the test was that the separators installed in the process development unit were found to be inadequate to insure acceptable turbine blade life or to meet current EPA particulate exhaust emissions standards. Further engineering is being conducted.

Supporting studies are being carried out at the Argonne National Laboratory under the sponsorship of ERDA. Initial research and development of the pressurized fluidized bed combustion done by this laboratory included eleven experiments to measure the effects on variables of temperature, fluidizing gas velocity, and ratio of calcium content of the dolomite to the surfur content of the coal. In these

experiments, Pittsburgh seam coal was burned at 8 atmospheres in a 3-foot-high fluidized bed and with 3 percent oxygen in the flue gas. The results indicated that:

(1) For calcium ratios above 2.0, more than 90 percent of the sulfur dioxide was retained in the dolomite bed; the amount retained decreased as the calcium-sulfur ratio decreased.

(2) Nitrogen oxide levels were extremely low, ranging between 0.40 and 0.15 pounds of nitrogen oxide per million Btu, as compared to the EPA emission standards of 0.70.

(3) Combustion efficiency varied directly with combustion temperature, ranging from about 89 percent at 1,450° F to about 97 percent at 1,650° F.

(4) Values of heat transfer coefficient varied directly with gas velocity, ranging from about 40 Btu/hour per sq. ft. per degree F at a gas velocity of about 2 ft./sec, to about 115 at 5 ft per sec.

Industrial Boiler Conversion

Although electric utilities have received the most attention with respect to potential for conversion to coal, American industry consumes more total energy and more energy-primary fuels than utilities.

In 1974, industry consumed about 40 percent of total U.S. energy input, including about 42 percent of total electricity. About 10 to 12 percent of the energy materials used directly by industry (other than coking plants) goes to feedstocks, the rest for fuel. The fuel is used for direct process heat (about 40 percent) and for steam (about 60 percent). About 30 percent of the steam is used to generate electricity.

Industry boilers have firing rates generally between 100,000 to 200,000 pounds of steam per hour and there are thousands of them. Only about 25 percent of all industrial steam is produced in plants generating 1 million pounds per hour or more, and about half in plants generating 250,000 pounds per hour or more.

Industrial energy consumption is concentrated in six major industries. Primary metals, chemicals, petroleum refining, food, paper, and stone, clay, and glass account for about 70 percent of total industry consumption.

Thus a technological breakthrough which would allow industry to convert to coal could have a significant impact on our national consumption of oil and gas.

ERDA is conducting a project which will consist of a feasibility study and preliminary design for potential industrial and institutional application of pressurized fluidized-bed concepts. The design, construction, and operation of prototypes on industrial and/or institutional sites for such purposes as captive in-plant generation of power, use of surplus heat for space heating, manufacturing processes, waste disposal, and so forth, will follow.

Although industrial boiler and process heater needs are quite diversified, a relatively small number of equipment configurations define the majority of applications. Thus, key components can be constructed on an industrial scale to determine the applicability of fluidized-bed combustors to industrial units.

ERDA has issued a program opportunity notice (PON) covering four different categories of industrial fluidized-bed boilers and process heaters. This PON identifies four categories of application of the fluidized bed concept, i.e., indirect steam generator, industrial boiler, indirect and direct fired heaters. The PON was released September 11, 1975, and thirteen responses were received. On June 17, 1976, ERDA announced that eight groups had been chosen to negotiate contracts. Contractors will share up to 50 percent of the costs.

Members of the subcommittee expressed a desire during the hearings to see more work done on the potential for retrofitting industrial and powerplant boilers. It was their opinion that such retrofitting would accelerate the utilization of coal in our Nation's economy. However, most of the testimony received showed a reluctance on the part of the utilities and industry to investigate the retrofitting option. In many cases this was based on a lack of information or misinformation as to outage times and economics. In fact, testimony that was received on an example of an industry retrofitting its boilers, showed that it occurred during a period of the most extreme emergency, i.e., a cutoff of fuel. The subcommittee hopes that ERDA's program for the retrofitting of industrial boilers will include cooperation and coordination with industry to maximize the retrofitting option.

SECTION 4—EXISTING ALTERNATIVES TO FURTHER COAL COMBUSTION RESEARCH

Existing Coal Combustion Systems

A logical next step in this review is the examination of the existing solutions to the problems of coal combustion and clean-up. To begin, the presently available systems for direct combustion of coal will be examined. There are three such systems: pulverized-coal systems, bin systems, and direct-firing systems.

1. PULVERIZED-COAL SYSTEMS

The function of a pulverized-coal system is to pulverize the coal, deliver it to the fuel-burning equipment, and accomplish complete combustion in the furnace with a minimum of excess air. The system must operate as a continuous process and, within specified design limitations, the coal supply or feed must be varied as rapidly and as widely as required by the combustion process.

A small portion of the air required for combustion (15 to 20 percent in current installations) is used to transport the coal to the burner. This is known as primary air. In the direct-firing system, primary air is also used to dry the coal in the pulverizer. The remainder of the combustion air (80 to 85 percent) is introduced at the burner and is known as secondary air.

The two basic equipment components of a pulverized-coal system are:

(a) The pulverizer which pulverizes the coal to the fineness required.

(b) The burner which accomplishes the mixing of the pulverized-coal-primary-air mixture with secondary air in the right proportions and delivers the mixture to the furnace for combustion.

Two principal systems—the bin system and the direct-firing system—have been used for processing, distributing and burning pulverized coal. The direct-firing system is the one being installed almost exclusively today.

2. BIN SYSTEM

The bin system is primarily of historical interest, although a large number of units of this type remain in operation. Its use was required before pulverizing equipment had reached the stage of development where it could be relied upon for uninterrupted operation, flexibility and consistent performance.

In this system the coal is processed at a location apart from the furnace, and the end product is pneumatically conveyed to cyclone collectors which recover the fines and clean the atmosphere. The pul-

verized coal is discharged into storage bins and later conveyed by pneumatic transport through pipelines to utilization bins which may be as far as 5,000 ft. from the point of preparation.

Although bin systems installed in older plants are still operating quite satisfactorily, this system is no longer competitive with the direct-firing system. Furthermore, the drying, transportation and storage of pulverized coal, other than anthracite, involves a fire hazard from spontaneous combustion.

3. DIRECT-FIRING SYSTEM

The bin system has been superseded by the direct-firing system because of improvements in safety conditions, plant cleanliness, greater simplicity, lower initial investment, lower operating cost, and less space requirements.

The pulverizing equipment developed for the direct-firing system permits continuous utilization of raw coal directly from the bunkers where coal is stored in the condition in which it is received at the plant. This is accomplished by feeding the raw coal directly into the pulverizer, where it is dried as well as pulverized, and then delivering it to the burners in a single continuous operation.

There are two direct-firing methods in use—the pressure type, which is more commonly used, and the suction type. In the pressure method, the primary air fan, located on the inlet side of the pulverizer, forces the hot primary air through the pulverizer where it picks up the pulverized coal, and delivers the proper coal-air mixture to the burners. In the suction method, the air and entrained coal are drawn through the pulverizer under negative pressure by an exhauster located on the outlet side of the pulverizer.

Finally, it should be noted that there are significant differences between coal-burning power generation systems and oil-burning systems. Therefore, plans to convert oil burning plants which have not been designed to use coal require not only particulate and sulfur-oxide emission controls, but additional power generating capacity as well. Any boiler which uses coal to produce electricity generally is less efficient than a boiler that operates on oil.

Excess Electric Generating Capacity

Members of the Subcommittee raised the issue during the hearings about what excess capacity exists in the electric utility business. If little new capacity is needed before 1980 or 1985, then the focus of research funding would change. It would also indicate whether or not any new technology would be assimilated into the economy quickly, with expansion, or only as replacements, as unit life expires. If the latter is the case, then the technology of retrofitting existing boilers should be vigorously pursued.

Electricity cannot be efficiently stored, causing the electric utility business to operate its supply and demand relationships in essentially instantaneous terms. Energy consumption in peak capability (installed and available Kw) are important subjects to the

utility business. Daily, weekly, and seasonal variations in load affect both of these and require that some power generation units be predominantly steady-state (base-load). Other units vary with load swings, and yet others start up solely to meet short-term peak demands. The accompanying figure shows a typical weekly electricity demand:

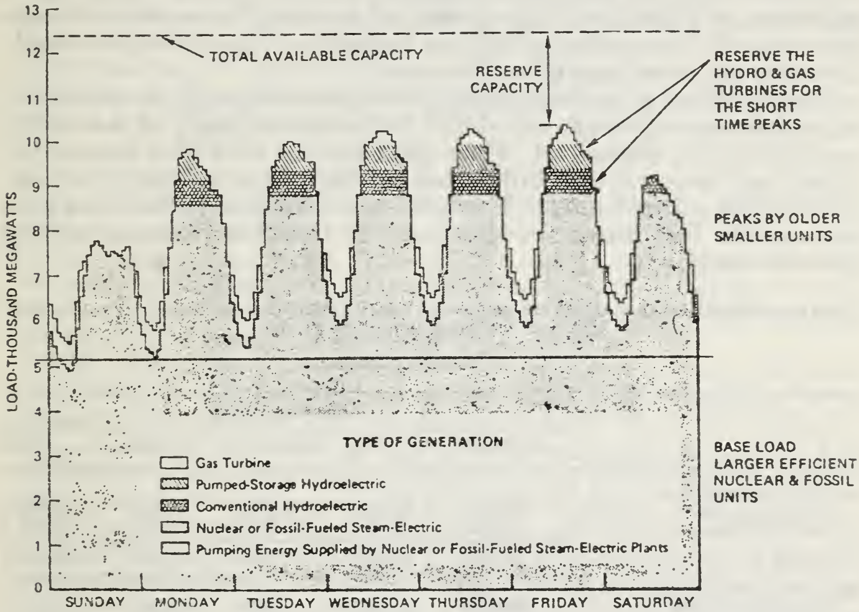


FIGURE 4–1.—U.S. typical weekly electricity demand.

Source: "U.S. Engineering Prospects; An Engineering Viewpoint," NAE, 1974, p. 50.

As can be seen from this typical-demand chart, there is a portion of reserve capacity. Testimony received by the subcommittee concluded that this excess capacity was almost entirely used up, in normal operation. This excess capacity is relied upon for general maintenance and for unexpected and unscheduled outages. In discussion with the witnesses, the members also concluded that this reserve capacity could not be relied upon for the flexibility necessary in outages for retrofitting existing plants. It could therefore be concluded that such existing excess capacity was normal operating procedure and did not indicate any "slack" in our Nation's electric generating capacity.

Finally, consideration of testimony by the National Coal Association showed a substantial increase in the number of coal-fired electric generation plants over the next five years.[1] Thus excess capacity is not an alternative to further research on new coal combustion technologies because new units are needed and will be constructed in the future.

[1] 136 new units planned or committed. Testimony by Carl Bagge before the Senate Committee on Public Works, June 10, 1975.

Use of Low-Sulfur Coal

EPA in a report required by the Energy Supply and Environmental Coordination Act said that of the 390 million tons of coal used in power plants in 1974, 194 million tons would meet requirements contained in State air quality implementation plans. Of the remainder, the use of 85 million tons are subject to litigation and 111 million tons are nonconforming. Plans have been developed for compliance where 46 million tons of noncomplying coal are burned, but have not been developed for the remaining 65 million tons.

This problem of noncomplying power generation plants could conceivably be solved by the use of this Nation's vast supply of low-sulfur coal. The U.S. Bureau of Mines estimated in 1974 that east of the Missisippi there were 33 billion tons of high-Btu coal, with one percent or less sulfur content. The table which follows is the latest estimate by the U.S. Bureau of Mines of total coal reserve base according to sulfur range:

TABLE 4-1.—DEMONSTRATED COAL RESERVE BASE IN THE UNITED STATES ON JANUARY 1, 1974, BY GEOGRAPHIC AREA AND POTENTIAL METHOD OF MINING[1]

In millions of tons]

	Sulfur range, percent				
	Less than 1	1 to 3	More than 3	Unknown	Total
East of the Mississippi River:					
Underground minable	27,471.2	48,642.9	65,992.3	26,545.5	168.684.2
Surface minable	5,385.4	6,823.7	15,434.7	5,969.3	33,628.2
Total	32,856.6	55,466.6	81,427.0	32,514.8	202,312.4
West of the Mississippi River:					
Underground minable	99,457.6	10,757.3	7,727.9	13,216.1	131,155.5
Surface minable	67,866.8	26,773.7	3,516.2	5,106.8	103,257.5
Total	167,324.4	37,531.0	11,244.1	18,322.9	234,413.0
Total east and west of the Mississippi River	200,181.0	92,997.6	92,671.1	50,837.7	436,725.4
Underground minable:					
East of the Mississippi River	27,471.2	48,642.9	65,992.3	26,545.5	168,684.2
West of the Mississippi River	99,457.6	10,757.3	7,727.9	13,216.1	131,155.5
Total	126,928.8	59,400.2	73,720.2	39,761.6	299,839.7
Surface minable:					
East of the Mississippi River	5,385.4	6,823.7	15,434.7	5,969.3	33,628.2
West of the Mississippi River	67,866.8	26,773.7	3,516.2	5,106.8	103,257.5
Total	73,252.2	33,597.4	18,950.9	11,076.1	136,885.7
Total underground and surface minable	200,181.0	92,997.6	92,671.1	50,837.7	436,725.4

[1] Data may not add to totals shown due to rounding.

Source: U.S. Bureau of Mines Mineral Industry Survey, Demonstrated Coal Reserve Base of the United States by Sulfur Category, on Jan. 1, 1974, published May 1975.

This shows an amazing total of over 200 billion tons of minable low-sulfur coal available in the United States.

However, there is an economic tariff that must be paid in converting to low-sulfurcoal. Electric Power Research Institute estimates that the capital cost of converting a coal-burning plant from high-sulfur coal to low-sulfur coal varies with plant size, averaging about $20 per

kilowatt of electric generating capacity. This expense includes minor boiler modifications plus upgrading of the particular emission control system. Low-sulfur coal prices, although highly variable, are generally higher than for high-sulfur coals. EPA estimates this differential at from 10–25¢ per million Btu on an average cost of about 70¢ per million Btu of coal.

However, these economic considerations may soon be eclipsed by more stringent environmental standards. Proposals for achieving national sulfur oxide ambient air quality standards require that approximately 80 percent of all coal consumers in existing powerplants in the United States after 1975 be less than 1 pound sulfur per million Btu. The Environmental Protection Agency's new source performance standards will similarly require all new coal-fired powerplants to consume coal with less than 0.6 lb. sulfur per million Btu.

The Western coal from the Rocky Mountain Region at the 0.6 lb. sulfur per million Btu level could potentially support Eastern coal burning steam generation demands for many years. However, 1974 Western production for electric generation is only estimated at 60 million tons per year, and the most optimistic 1985 production estimates are set at only about 116 million tons per year.[2]

With these difficulties arising in increased production of Western coal, it seems apparent that we should explore the possibility of increased production of Eastern low-sulfur coal. The U.S. Bureau of Mines estimate that there is approximately 32.8 billion tons of low-sulfur coal in the East,[3] with 13 billion tons of recoverable low-sulfur, deep-mined bituminous coal in West Virginia alone.[4]

Testimony revealed that the increased production of low sulfur coal had not been seriously considered by the utility industry as an alternative to technologically intensive solutions. EPRI testified that they considered the option of installing new facilities for low sulfur coal to be equally desirable as the high technology solutions, where costs were equivalent. However, to date, the level of production necessary to justify their reliance on this option has not come forth, requiring them to pursue these technologically intensive solutions.

Members of the subcommittee felt that the low sulfur coal reserve base represented a very real alternative to further capital expenditure by utilities for new technology, to burn coal in an environmentally acceptable manner. However, recognizing the large capital expense required to open new mines, members of the subcommittee wished to see further refinement of the data. They wanted to know the amount of coal which can be obtained from either existing deep mines that are currently in operation or from those deep mines that have been shut down in the Eastern United States. Discussion between the panel and the witnesses revealed that Bureau of Mines does not seek this data, on the basis that this is proprietary information of the coal companies. Members felt, however, that this presented a real alternative to further funding of research, and that ERDA should consider this question jointly with the Bureau of Mines and others; ERDA agreed to research this matter.

---

[2] Carl Bagge, NCA, ibid.
[3] U.S. Bureau of Mines Mineral Industrial Survey, January 1, 1974, published May, 1975.
[4] Ibid.

Further testimony from EPA indicated that the low sulfur coals of the West may provide further environmental problems. EPA stated "Under the present environmental control standards set by the Environmental Protection Agency, many of the low sulfur coals will meet the standards, both sulfur dioxide and particulates, at the present time. It depends, though, critically on the nature of the coal. The very good eastern coals, such as Mr. Hechler referred to, will meet both the particulate and the sulfur dioxide standards without difficulty. However, as you move into the west, some of the coals are really quite different. They have lower Btu content; they have higher ash content; and there are problems in that some of the coals which might have a .7% sulfur by weight would not meet the sulfur dioxide emission standards or the particulate emission standards because of the different problems which are created by the lower heat content, the high ash content."

Such testimony indicates that the eastern coals should be at least as vigorously developed as the western low-sulfur coals.

Flue Gas Desulfurization Systems (FGD)

Flue gas desulfurization, the center of a continuing controversy, is a relatively new technology for electric utilities. Part of the controversy relates to the question of its reliability in operation, part to its demand for capital, and part to its necessity compared to other control options, particularly tall stacks and noncontinuous controls.

As of October, 1974, there were 19 flue gas desulfurization (FGD) systems in operation in the U.S. on units with electric generating capacity of 3,291 megawatts. Eighteen units were under construction, nine construction contracts had been awarded, and an additional 53 systems were under consideration.[5]

EPA, in its report (dated February, 1975), lists flue gas desulfurization (FGD) among the available compliance options and claims that "newer units are expected to realize 95 to 99 percent availability over long time periods" and that "the lime/limestone scrubbing, Mag-Ox, and Cat-Ox processes are the most advanced and hold the greater promise for near-term commercial applications." An NAS-NAE-NRC report, however, does not consider Mag-Ox and Cat-Ox as having been operated long enough on coal-fired units to provide a basis for judgment of availability. Another report, by the AEC to the Council on Environmental Quality, however, agreed with EPA and rated the magnesium oxide and catalytic oxidation systems as being the most readily available for commercialization purposes. The results of that study appear in the following table:

---

[5] EPA Report, February 1975,, EPA–450/1–75–001.

TABLE 4-2.—TECHNOLOGICAL STATUS OF SOME STACK-GAS SULFUR DIOXIDE-REMOVAL PROCESSES

Process	Major U.S. engineering participants	Status of demonstration plants		Status of process chemistry	Major technological problem areas
		U.S. plants operating on coal of greater than 2 percent sulfur	Other plants, United States and foreign, operating on oil or low-sulfur coal		
Magnesium oxide wet scrubbing	Chemico	100-MW unit near startup	2 150-MW units in operation; United States on oil, Japan with throwaway cycle.	No major uncertainties	Ash removal requirements.
Sodium solution scrubbing	Wellman-Lord	125-MW unit under construction.	250-MW unit near startup for coal of 1 percent sulfur. Smaller units of several types operating without difficulty.	Additives required to minimize oxidation to Na_2SO_4.	Sulfate formation requires waste bleed and caustic makeup.
Catalytic oxidation	Monsanto	100-MW unit completed in 1972 but not yet in operation.	Small units for process development only.	Apparently no problems	Ash removal requirements; high operating temperatures; catalyst attrition; low H_2SO_4 quality.
Limestone into boiler with wet scrubbing.	Combustion Engineering	Shut down as a result of continuing operating difficulties.	No additional plants; scheduled units have been canceled.	Complex $CaSO_4$ scaling difficult to control.	Severe boiler operating problems; poor limestone utilization; severe scaling, demister plugging.
Wet scrubbing with lime slurry feed.	Combustion Engineering Chemico.	Several near startup	Successful operation of 150-MW unit in Japan on coal of 2 percent sulfur; other plants operating.	Complex $CaSO_4$ scaling difficult to control.	Severe scaling, demister plugging.
Wet scrubbing with limestone slurry feed.	Babcock and Wilcox, Combustion Engineering, TVA.	175-MW unit completed in 1972; has not yet met acceptance tests; many others of greater than 100-MW under construction.	Small scale development units only.	Complex, not completely understood; blinding of limestone surface a problem.	Demister plugging; poor dependability; low limestone utilization; waste sludge disposal.

Source: AEC, 1974: Vol. IV, p. A.2–26.

During the hearings, the Subcommittee received testimony from EPRI on the details of operating FGD and some problems that have been encountered therewith. EPRI testified that there were, at present, two FGD systems:

> Throwaway systems, in which spent materials must be disposed of, and "regenerative" processes, wherein saleable products are produced. For both system types very limited full-scale experience has been obtained. The operating procedure for throw-away systems calls for the flue gas to be scrubbed with a 5 to 15 percent slurry of calcium sulfite/sulfate containing small amounts of continuously added lime or limestone. The resulting reaction converts the sulfur dioxide gas to a slurry sulfate or sulfite. These processes require a scrubber incorporating liquid contactors and mist eliminators, gas fans, ductwork, and dampers and gas reheaters to restore plume bouyancy. If fly ash particles are not removed by an electrostatic precipitator, the scrubber system must be designed to allow for particulate as well as SO_2 removal. The processes are complicated by simultaneous dissolution and crystallization of the solids in the scrubber. Calcium scaling and plugging can occur in the scrubber and demister, and sufficient residence time and liquid recirculation must be provided for reaction of the solids with the sulfur dioxide. In addition, the high solids concentration tends to cause equipment corrosion and erosion. The key to control of these problems is careful maintenance of the scrubber operating conditions.
>
> A number of regenerable systems have been developed to produce a saleable product, such as elemental sulfur, or sulfuric acid. Elemental sulfur appears the most attractive product in terms of environmental impact, production rates, and potential storage volume. About 90,000 tons per year of sulfur would be produced by a 1,000-MWe power plant using 3 percent sulfur coal. At this rate, the control system of 100 Gwe of coal-fired capacity would produce sufficient sulfur to meet the total U.S. sulfur demand. The lack of long-term experience with these regenerable systems currently is a disadvantage; however, promising results have been obtained in a number of pilot and demonstration scale plants.
>
> Investigations of possible uses for sludge as a raw material have failed thus far to show that scrubber sludge has a ready market. One problem complicating this issue is the variability of scrubber sludges formed from coals, as well as limestones of different properties, coupled with the presence of fly ash in the sludge. These sludges contain various proportions of calcium sulfite, gypsum, fly ash, and water.
>
> Practical application of flue gas desulfurization technology to existing coal-fired power plants is affected by considerations such as plant design, available space, age, and capacity-use factor. These characteristics have a very important impact on installed process costs and can be expected to limit the utilization of flue gas desulfurization in existing coal-fired power plants to about 40 percent of presently existing plants.

With regard to the capital costs, FEA estimates that FGD will cost about $67 per kilowatt in new power plants, while EPA estimates between $60 and $100 per kilowatt. The NAS report also estimates $60 to $100 per kw on the basis of reports from utilities and vendors, with "the majority believing that the costs will be closer to $100/kw."

For retrofitting existing power plants for FGD, FEA estimates an average capital cost of $87 per kw. The NAS report shows that retrofitting is estimated to cost 20 to 30 percent more than for a new plant, while Ebasco Services, in a report to FEA on the cost of converting 10 specific oil burning plants to coal, estimates the total air quality control system at $175 to $300 per kw, with the FGD component ranging from $90 to $160 per kw.

Most estimates of loss of generating capacity from FGD range between 3 and 6 percent. NAS, in it report, estimates 5 to 7 percent. FEA, in its ESECA Environmental Impact Statement, estimates FGD operating costs at 1.9 mills per kwh, while the NAS study shows a 2.0 to 2.5 mil per kwh range and a judgment that this range is probably too low.

FEA estimates that a price differential of $10 or more per ton between low and high sulfur coal makes FGD economic compared to low sulfur coal. The differential is not currently that great on the average but low sulfur coal prices can be expected to increase along with the mandated demands for emission limitations.

Pre-Cleaning Coal

This last alternative is the most widely utilized and the lowest cost option today. Its effect is limited because it does not remove 100 percent of the sulfur or other potential pollutants. EPA estimates that 13.6 percent of U.S. coal reserves can be cleaned to new source performance standards specifications (1.2 pounds of SO_x per million Btu) and an additional 54.6 percent can be cleaned to less than 4 pounds of SO_x per million Btu. Thus this technology may present an attractive alternative to further research funding for the next term and may also offer the best chance of near term results in R & D.

EPRI offered testimony on the status of present precleaning technology and its utilization. It stated:

> Sulfur in coal exists in two principal forms, organic and inorganic. The organic sulfur is chemically bound to the coal substance and cannot be physically removed. However, inorganic sulfur (pyritic) is not bound chemically, and may be removed in a two-step process. This process involves (1) crushing, and (2) physical separation, which most commonly is effected by exploiting the difference in specific gravity between coal and pyrites. The degree of removal is dependent upon pyrite size and distribution, coal size, and other physical characteristics. Typically, the costs associated with this technology for high-efficiency pyrite removal are $1.00 to $5.00 per ton of coal cleaned.
>
> Existing cleaning processes, while removing impurities from coal, also reduce the total energy content available because some of the coal is lost with the refuse. However, the heating value of the cleaned coal increases due to removal of low heating value impurities. In practice an economic balance must be achieved between the Btu loss and the improvement in coal quality. This balance is further influenced by environmental considerations in disposal of the reject material, which has an extremely high water pollution potential because of its concentrated sulfur, iron, and trace metal content. In practice these trade-offs demand at least 90 percent Btu yield from the feed coal. This typically results in the rejects containing 15 percent of the feed weight. Another negative environmental factor associated with physical coal cleaning includes fugitive dust emissions from storage and refuse piles, as well as conveyor systems. Thermal drying to reduce washed coal moisture content can also contribute particulates, sulfur oxides (SO_x) and nitrogen oxides (NO_x) if low grade heating fuels are used and emission control systems are not applied. These emissions are effectively prohibited in new coal preparation plants by the new source performance standards.
>
> The most environmentally acceptable aproach is to achieve utilization of all materials in the coal. The refuse material would be processed into various products: rock refuse for nonpolluting disposal; a pyrite concentrate that subsequently could be commercially converted to sulfur acid; and coal products of various sulfur levels for burning.
>
> The major limitation to the use of physical coal cleaning as an environmental control method is the degree of sulfur removal. Sulfur reduction studies of U.S. coals have been performed by the Bureau of Mines and EPA on 332 coal samples representing most mine-producing seams. The results indicate an average total sulfur reduction of only 30 percent at a raw coal top size of ⅜ inch and washed to a 90 percent Btu yield. This restricts coal producing regions to a limited number in which the potential exists for washing coal to a total of 1 lb. sulfur per 10^6 Btu or less. Those regions would include the Northern Appalachian, Southern Appalachian, and Eastern Interior. Within these regions only about 15 percent of total bituminous coal production appears to be physically cleanable to less than 1 lb. sulfur/million Btu. The potential for washing coal is greatest in the northern Appalachian underground mines.

This alternative requires further technical research in combustion, and appears to be one of the most adaptable options for burning coal in an environmentally acceptable manner. Coal can be pre-cleaned at either the mine, en route, or just prior to combustion.

Supplementary and Intermittent Control Strategies

One of the simplest technological methods of controlling sulfur emissions is with a combination of careful weather monitoring and tall stacks. The Tennessee Valley Authority stated that, "at existing plants, TVA believes that curtailment of load during adverse meteorological periods in combination with tall stacks provides the most cost-effective method for compliance with SO_2 ambient standards."

TVA has used this method in western Kentucky, an area with coal of four and a half percent sulfur at a plant in Paradise, Kentucky, which has stacks over 600 ft. in height. The first step in their program was to compile an atmospheric model to study the conditions that brought on high ground level concentrations of sulfur. From this model, a predicting procedure was developed with airplane flights to confirm the temperatures and other meteorological conditions. By instituting load curtailments when conditions were unfavorable, TVA was able to avoid building up a reservoir of sulfur dioxide that would later be brought down to ground level when air currents shifted. But utilizing this program for over 3 years, they testified they were able to hold sulfur dioxide emissions below the standards established by their own health and safety department and below those standards later established by the EPA.

EPRI offered testimony, which, in general, agreed with the success claimed by the TVA. EPRI also concluded that such strategy would be effective if stack heights at other plants were sufficient. When atmospheric conditions are unfavorable, such as an air inversion, low sulfur fuel or production restrictions are used.

EPRI noted the limitations which this technique has:

(1) An accurate inventory of source emissions and regional meteorological data must be compiled.

(2) An accurate regional research program must be conducted on the atmospheric transformations affecting hydrocarbons, oxides of nitrogen, oxidants, and sulfates.

However, these requirements are not technologically intensive, nor do they depend on new generations of hardware.

EPRI concludes that this technique can only be relied upon as a tactical, near term expedient until reliable impact and control criteria for sulfates and other secondary particulate emissions can be defined. More stringent air standards will require more sophisticated technology to control the emissions. The use of tall stacks will be inadequate, concludes EPRI, for achieving the necessary ground level ambient conditions.

SECTION 5—OTHER AREAS OF COAL COMBUSTION RESEARCH AND DEVELOPMENT

Pulverized Coal

Pulverized coal offers the advantages of (1) the most thermally efficient way to utilize coal and (2) simplicity of operation. Industry prefers this type of direct firing of coal, for just these reasons. However, utilities object to pulverization of coal for their operations because it uses up too much energy for the amount of energy derived, At present, there are commercially available grinding processes which will yield particles of coal less than 100 microns in size. For future development are systems to pulverize coal to less than 10 microns in size.

The main problem with pulverizing coal is that there is a large amount of energy consumed in further reducing the size of the coal particles. The decreasingly smaller sizes result from repeated passes through the equipment, or more equipment in line. There comes a tradeoff point where the amount of energy expended in further pulverization will go beyond the amount of energy derived from the coal itself. In engineering, this relationship is expressed as Bohr's Law.[1]

Calculations of pulverization to various sizes yields some interesting results, regarding the amount of energy consumed. The ratio of the energy required to produce various-sized particles significantly increases as the size decreases. For example, a comparison of 74 micron coal to 10 micron coal, to 5 micron coal yields an energy consumption ratio of 1:2.72:3.85.[2]

[2] $$E_1/E_2 \simeq \left(\frac{10}{\sqrt{x_{P1}}}-\frac{10}{\sqrt{x_{F1}}}\right)\Big/\left(-\frac{10}{\sqrt{x_{P2}}}-\frac{10}{\sqrt{x_{F2}}}\right)$$

where E is energy per ton to produce a product of which 80% by weight is less than size X_P, from a feed of 80% by weight of less than X_F in size.

This energy consumption ratio is related to the amount of capital which must be invested to achieve these increasingly smaller sizes. Thus, it would require roughly four mills to produce five micron material, compared to one mill for the conventional size pulverized coal of 74 microns.

At present, there are three types of mills which can produce this pulverized coal.[3]

The first type of mill is the roll-race mill, commonly used for grinding coal to prepare pulverized fuel. It has been used in the German cement industry to prepare fine finished cement. The second type of mill is the high speed hammer mill, again used in Germany, to prepare pulverized fuel. The use of extra stages with higher hammer velocities and repeated passes through the machine can give fine sizes.

[1] Testimony of Dr. Robert Essenhigh, Pennsylvania State University, to the Subcommittee on Energy Research, Development and Demonstration (Fossil Fuel), July 1975, App. 4.
[3] Ibid.

The third type of mill is the conventional tumbling ball mill, which will reduce coal to fine sizes. Ball mills are used in industry and produce up to two tons per hour; this rate of output is considered too small for utility purposes.

The Ilok technology claims to be able to remove pollutants from finely pulverized coal by a process of thermal shock treatment. The coal is reportedly reduced in size from 4 microns to 1/300 micron and simultaneously stripped of all contaminants—ash as well as organic and inorganic sulfur. Testimony received by the Subcommittee was somewhat skeptical of these claims. The mill that is used in this process was invented by Dr. Hans Rohrbach, and has been recently advertised by the Perolite Co. Dr. Rohrbach has provided only one public, technical statement on the Ilok technology. This was in the Journal Motortechnicsche Zeitschrift, on page 379 (1971). The title was, "On Some Problems of the Coal Dust Motor." Testimony before our subcommittee revealed that a search of the hearings of other House Committees and of patent records has revealed no patents on the mill.

The subcommittee received testimony that the theory of operation of the Ilok technology is supported by various studies. The inorganic sulfur in coal, called pyrites, are bonded together. Once the coal is pulverized to a very small size, the pyrites will separate out into separate particles. One process that could be used to separate the pyrites out would involve a vertical pipe with a high velocity stream of nitrogen. The nitrogen would travel at 200–300 miles an hour, and hit an analus, reducing the velocity, and then travel around a bend. The mineral matter would then collect on the outer side of the bend, and could then be tapped off.

In addition, magnetic separation could be used to separate the pyrites. This could be done by first lightly oxidizing the coal, and then passing it through a magnetic field. The oxidation increases the magnetic potential of the pyrites and will permit a high percentage of separation. The organic sulfur would be separated by the further reduction of the coal to $\frac{1}{300}$ micron.

Coal and Oil Mixtures

These mixtures are particularly attractive in process furnace applications. They are easy to adapt to the existing equipment. After adaptation to process furnaces, it quite naturally follows that industrial furnaces would pick up such a fuel type. With our current energy resource shortages, this could result in a substantial amount of furnace capacity being converted to coal and oil mixtures by 1980 or 1985. The Subcommittee received convincing testimony that industry was ready to rapidly assimilate such technology when and if it becomes available. General Motors is now conducting an accelerated program to develop the necessary engineering to convert its boilers to coal/oil mixtures.

Research and development on coal and oil mixtures has been going on for 50 years, particularly at Penn State University. In 1932, a ship crossed the Atlantic with all 5 boilers fed by coal/oil mixtures. Recently, Penn State has published a study on this type of fuel, entitled, "Colloidal Fuel Develpment for Industrial Use."

There are many attractive aspects of coal and oil mixtures which would cause industry to utilize this fuel type. In the first place, it requires only a modification of existing equipment to accommodate the new volumes of fuel. It does not require any major degree of replacement of existing equipment. Secondly, sulfur emissions can be handled by varying the type of coal and oil mixture. Either a high-sulfur coal and a low-sulfur oil can be used in varying percentages, or the reverse could be tried. In any event, this would provide an attractive interim solution to sulfur emission problems.

ERDA issued a program opportunity notice (PON) in February, 1976 seeking proposals to modify, operate and test existing boilers, heaters and furnaces, including the construction of a slurry mixing/distribution facility. Seven firms submitted proposals to the Energy Research and Development Administration for the combustion of coal-oil slurry as a principal fuel for industrial and utility use, and four groups have been chosen.

APPENDIX A—ENERGY CONVERSION ALTERNATIVES STUDY (ECAS)

Purpose of the Study

The primary goal of the ECAS study is the identification and comparison of options for the future generation of electricity, using coal and coal-derived fuels. ECAS was conducted using a common basis of technology and performance to compare each of ten different power generation systems. ECAS put together some development plans for the various advanced systems, providing estimates of both cost and risk, and also providing a basis for establishing needed technology or development programs. The evaluation of alternative systems on a comparable basis is needed so that cost-benefit analysis may be performed and the preferred systems selected for further development.

In particular, those Federal agencies concerned with power plants and electric generation for the future need these answers to develop a coordinated strategy for future energy development. The ECAS study combines the funds of three agencies, the NSF, ERDA, and NASA, the cooperation of the Department of the Interior and the Environmental Protection Agency, and the combined expertise and experience of the Westinghouse Corporation and General Electric Company. Overall coordination is provided by NASA's Lewis Research Center.

The importance and need of this study is readily apparent. Electric utilities provide approximately 25 percent of our Nation's energy output. However, they are at present less than 40 percent efficient in converting our energy resources to electricity. In this period of our Nation's energy shortages, we must strive to conserve energy at every level. Both the Federal Government and the public utilities have many types of electrical generation systems for future needs. However, they do not have a common basis on which to evaluate many of the proposed systems. Decisionmakers in the Government and in public utilities need some way to evaluate these systems, so that they may decide which technology will make the most efficient use of our Nation's energy resources.

Structure of the Study

The ECAS study was organized to take advantage of the offices of the principal agencies, ERDA, NASA, and EPA. The study itself was conducted in parallel by two contractors, Westinghouse and General Electric. As can be seen from the accompanying organizational chart (figure 1), there are many steps of review for the results of this study, consisting of both a technical review panel and a utility review panel. Also to be noted are the separate contracts to develop data for impact and benefits assessment.

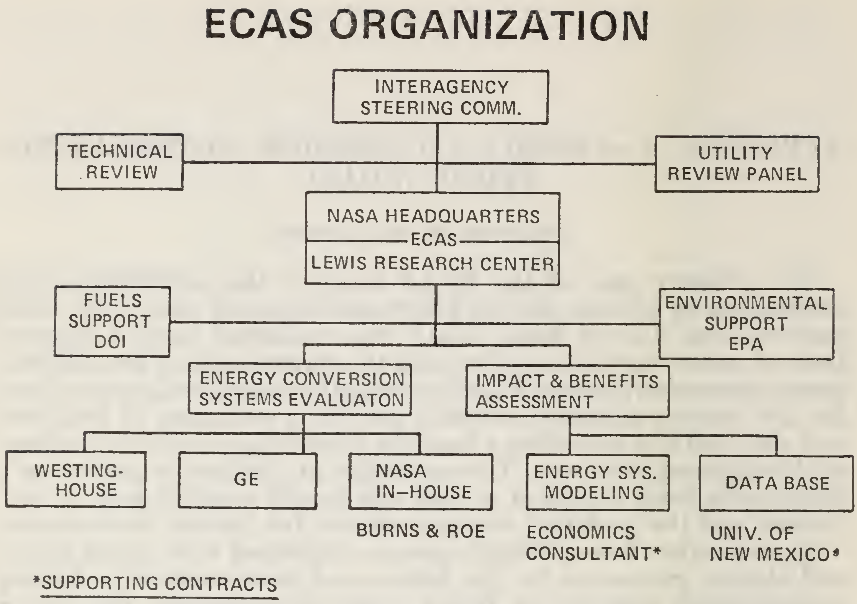


FIGURE 1

Source: NASA.

In designing the ECAS study, NASA chose from numerous proposals, and selected the following ten candidates for electric generation systems: Advanced Steam, Open Cycle Gas Turbine; Closed Cycle Gas Turbine; Open Cycle MHD; Closed Cycle MHD; Liquid Metal MHD; Super Critical CO_2; Liquid Metal Rankin; Fuel Cells; Combined Cycle (Gas Turbine and Steam).

Each of these advanced concepts is backed by an industrial proponent who sincerely believes that his option has merit and should be pursued. Obviously, the ECAS study cannot pursue every option with equal priority. It is the purpose of ECAS, however, to undertake a study to relate these various approaches to a common frame of reference.

The ECAS study was divided into two phases. In the first phase, the contractors evaluated the potential of the ten candidate systems of advanced energy conversion, with various coal-to-thermal energy processes. In this phase of the study, the contractor examined plant efficiency, capital costs, and the cost of electricity.

The second phase consisted of two parts. The first was a conceptual design of promising specific plants. The second part of this phase was an implementation assessment of each of these conceptual designs.

In this last phase, NASA assessed the implementation of the conceptual designs along the following criteria: Economic Viability; Efficiency/Fuel Conservation; Natural Resource Requirements; Environmental Impact; Reliability; Safety; Life Limitations; System Component Compatibility; Siting; Application Flexibility; Operation/Control; Maintenance; Retrofit Potential; Byproduct Production; and Power Grid Compatibility.

The plan included an explanation of the power generation systems on a common basis by NASA.

One area of particular interest to members of the subcommittee was the inter-agency cooperation that is necessitated by this organization. The subcommittee was particularly interested in the manner in which the various principal agencies were able to assimilate the expertise that was developed in each agency. NASA has developed experience dealing with certain large-scale system studies, whereas some of the ERDA predecessor-organizations did not have that type of experience. On the other hand, the Department of the Interior had possessed detailed knowledge of the coal resource base and utilization in the economy, whereas NASA would have had to develop this capability. It was noted in the hearings that in coordinating earlier programs the Office of Coal Research had worked out an agreement with NASA concerning developments in the area of coal combustion. However, there was a reluctance on the part of the Department of the Interior to let a new agency such as NASA get into an area where OCR had done a significant amount of work through the years. The Subcommittee was very much concerned that any type of bureaucratic delay would translate into a delay of the ECAS study.

Upon further questioning the subcommittee noted that the main problems in implementing working agreements between NASA and other agencies were legal ones, involving the differences between interpretations of the basic laws for each agency, specifically, the patent policies of those laws. In some cases it took more than a year to negotiate these differences, and some of these differences still remain in relationships between NASA and with the Department of the Interior; whereas negotiations are much further along with ERDA.

Other agencies perceive NASA's patent policy to be much more liberal than the policy under which they operate.[1] NASA has by legislation the option, in judging whether or not to retain patent rights, or to require background rights, to consider simply whether or not such retention or requirements would advance the dissemination of the technology into the private sector. They have the discretion to make a judgment whether or not the company keeps the patent, or has a license to it, or whether NASA retains the patent. This gives NASA an advantage in working with a highly developed technological industry. The industry realizes that in appropriate cases they can retain vast amounts of background information, on a proprietary basis. However, if the industry were working with another agency, the industrial applicant for federal assistance would have to release the patent and information if it were to take the contract, because most other agencies do not feel that they have that discretion.

However, the testimony shows that the agencies have started to make progress on interagency agreements. NASA does have a general agreement with ERDA and a general agreement with the Department of the Interior, and specific agreements on projects in solar energy. It is

---

[1] Cf. H.R. Rept. No. 1563, 93d Congress, 2d session at 26 (1974). The Conference Committee on S. 1283 in their report to both Houses pointed out that the basic structure of section 9 was derived from the Space Act with some modifications derived from the Atomic Energy Act. Some of the detailed criteria of section 9 were stated as being adopted primarily from NASA and AEC regulations, as well as from the Presidential Patent Policy Statement.

now actively developing agreements with ERDA in the fossil energy area. ECAS has an agreement that is already operating. It therefore appears that interagency agreements by which the special expertise of various government groups will be applied to a common problem can be achieved.

Another area of interest to the subcommittee was the parallel studies that were being conducted by two contractors in the ECAS study. This could possibly raise charges of duplication of work. It was noted in the hearing that this charge is not always applicable because an agency can move competitively toward a goal, even though it may seem that two groups are doing similar work on the same problem. The point was raised that by having two independent and parallel studies being conducted, there will be a degree of advocacy in the evaluations of the study. The agency, NASA, can then evaluate one study with the other, and by using a data base, developed independently, the contracting agency can develop an improved and more objective conclusion.

The Subcommittee also received testimony on one aspect of the commercial development which affects the rate of assimilation of the new technologies into the economic structure: the establishment of a normal commercial warranty for the new technology. In order to accomplish the transition from development stage to normal commercial equipment, the new technology must go through a demonstration phase, sometimes involving years of experience with both normal and abnormal operating conditions. The companies offering the new technologies must collect sufficient experience to justify any warranty they would be willing to give to the vendee. Until the vendor is ready and willing to give such a warranty, the acceptance of the new technology will, of necessity, be much slower than desired. The Subcommittee feels that the ECAS study should address this problem also and ERDA should similarly consider the impact of the need for a demonstration phase before a new technology will be commercially acceptable.

Members of the Subcommittee were very interested in the role of the Sierra Club in the ECAS study. The Sierra Club is considered valuable for its ability not only to assess real problems of a technology that will affect the environment, but also to identify and discuss perceived problems that may arise in the future. As long as a problem is perceived by a large mass of the public, it must be treated as a real problem before a new technology can be adequately accepted into our economic structure. Similarly, members of the Subcommittee expressed a desire to see representatives of a consumer organization on the review panels of the ECAS study. These representatives' input would be valuable to assess the effects of these new technologies on the consumers and, in general, to let the consumers have a greater opportunity to affect these decisions.

Phase I, the parametric analysis, has been completed and a report on the results thereof was issued in February, 1976. The results include performance and economic data, such as plant capital cost and cost of electricity, and emissions and natural resource requirements for selected cases. This report provides a comparative evaluation of the contractor results on both a system-by-system and an overall basis. Ground rules specified by NASA, such as coal specifications, fuel

costs, labor costs, method of cost comparison, escalation and interest during construction, fixed charges, emission standards, and environmental conditions, are presented. Each system discussion includes the potential advantages of the system, the scope of each contractor's analysis, typical schematics of systems, comparison of cost of electricity (COE) and efficiency for each contractor, identification and reconciliation of differences, identification of future improvements, and discussion of outside comments. Considerations common to all systems, such as materials and furnaces, are also discussed. Results of selected in-house analyses are presented, in addition to contractor data. The results for all systems are then compared. Maximum efficiency with corresponding COE and capital costs, minimum capital cost with corresponding efficiency and COE, and minimum COE with corresponding efficiency and capital costs are tabulated for each system and contractor. Plots of COE against overall energy efficiency for each system and contractor provide an insight into the effects of fuel, bottoming cycle, or gasifier and permit a ready comparison with the advanced coal-fired steam system. The sensitivity of COE to changes in capital costs, construction time, fuel costs, capacity factor, interest rate, escalation rate, and fixed-charge rate is determined as well as sensitivity to comparisons based on different methods of calculating COE.

Phase II of the study which was the conceptual design work has also been completed. NASA and the two technical teams headed by General Electric and Westinghouse made their results public in October, 1976.

Their evaluation indicates (even though uncertainties exist) that relative to the base case of conventional fossil fuel steam plants significantly lower cost of electricity and improved overall efficiency can result in the near term from the use of two technologies; fluidized bed combustion for power plants using conventional steam conditions and combined cycle plants in which an advanced open cycle gas turbine discharging into a steam bottoming plant is fueled by an integrated low-Btu gasifier.

Two technologies, closed cycle gas turbines with an organic bottoming cycle, and a liquid metal (potassium) cycle with a steam bottoming cycle were found to offer improved efficiencies with projected costs of electricity comparable to those of conventional steam plants. Enough uncertainty exists to warrant continued investigation of such systems.

Two technologies, open cycle (direct coal fired) MHD with a steam bottoming cycle and high temperature fuel cells operating with an integrated gasifier were found to offer substantially higher efficiencies, near 50 percent, and lower costs. These processes are in earlier phases of development.

The Energy Conversion Alternatives Study has been successful in determining the relative potential of the leading advanced technologies under the specified conditions. Further evaluation and implementation assessment is now being conducted by NASA.

O